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Compliance Problems of Small Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978: volume I

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Executive Summary

BACKGROUND

The Powerplant and Industrial Fuel Use Act of 1978 (FUA) prohibits the use of petroleum and natural gas in new powerplants, and prohibits the construction of new powerplants without the capability of using an alternate fuel as a primary energy source. The Act also restricts the pre-1990 natural gas use of existing powerplants which used gas in 1977 to retain historical base period proportions, and prohibits the pre-1990 use of natural gas in electric powerplants which did not burn gas in 1977 and the post-1990 use of natural gas in any electric powerplant. The Secretary of Energy may, under the Act, issue orders prohibiting the use of oil or gas in certain individual existing plants that are or have been capable of using coal or other alternate fuels. The Act defines as powerplants boilers, combined cycles, or combustion turbines whose fuel input design capability equals or exceeds 100 million Btu's per hour. This limit corresponds to approximately ten megawatts (10MW) electrical output (in some cases as low as 5MW). Most utility generators fall within these jurisdictional thresholds.

Among the options available to utilities, consistent with the foregoing prohibitions, are the following:

- o building new plants fired by coal or other alternate fuels.
- o converting existing gas-fired plants to oil (in the absence of an effective prohibition order) or alternate fuels, or retiring such gas-fired plants, by 1990.
- o converting to alternate fuels those oil fired plants which have been issued prohibition orders by DOE.
- o obtaining temporary or permanent exemptions for individual units, under a variety of conditions specified in Titles II and III of the Act.
- o negotiating with DOE a compliance plan for system-wide gas use, as specified in Title V of the Act.

Motivated by concerns that any of these options might prove to be an excessive burden to small utilities, Congress required, in Section 744 of the Act, that the Secretary of Energy conduct a study of the compliance problems of utility systems with less than 2000MW generating capacity.

CONDUCT OF STUDY

The study was conducted in Spring, 1980. During this period, ERA's "interim" rules (44 FR 23950, May 17, 1979, 44 FR 43176, July 23, 1979, 44 FR 28530, May 15, 1979) were in effect. Very few small utilities had reached decisions regarding FUA compliance strategies, but many had already been involved with the FUA program. This involvement entailed petitions for temporary public interest exemptions (allowing the short-term use of gas to displace oil in qualifying facilities) or preliminary meetings concerning system compliance under Title V of FUA. As of that time, however, no small utilities had applied for a permanent exemption.

The study attempted to identify the FUA compliance problems perceived by the small utilities, as well as the strategies they are considering by means of

- o meetings between DOE staff and representatives of over 100 small utilities.
- o meetings with trade associations, law firms, and technical consultants representing small utilities.

- a notice of inquiry (45 FR 26117, April 17, 1980) followed by a May 21, 1980, letter to 296 small utilities, resulting in 68 written responses.

- a public meeting in Dallas on May 15, 1980.

- case studies performed by or for DOE of ten representative small utilities and one joint agency.

Although a wide variety of small utilities were contacted, the study emphasized the utilities that depend heavily on natural gas, because they are the most likely to be severely impacted by the FUA.

The study identified and evaluated a variety of ways of alleviating the problems perceived by the utilities, including

- use of coal or alternate fuels on a scale compatible with a small electric utility system.

- institutional options by which small utilities can realize the benefits of large-scale powerplants (including a comprehensive survey of the status of joint action agencies and joint ownership projects).

- regulatory or procedural changes.

- statutory changes.

This report was written entirely by DOE staff, who are solely responsible for all findings and recommendations. It is based on information derived partly from DOE staff analyses, partly from a study performed by Radian Corporation, under contract to Oak Ridge National Laboratory, and partly from letters submitted by utilities and other interested parties (Appendix H).

FINDINGS

Small Utilities' Characteristics

There are 904 generating utilities in the United States with system capacity less than 2,000MW. Of these 435 have system capacity greater than 10MW--the approximate lower threshold for FUA coverage of a single unit. Fifty-three percent of these small utilities are municipally-owned, 9 percent are cooperatives, 25 percent are investor-owned, and 13 percent are government-owned. There are small utilities in all regions of the country, but the majority of them are in the central states.

One hundred and thirty-seven small utilities--located predominantly in the central states--generated over 50 percent of their power in 1979 from natural gas.

In 1979, small utilities (as defined in FUA Section 744) accounted for 20.5 percent of the total national generating capacity, and generated 21 percent of the nation's electric energy. The small utilities are about as dependent on natural gas and oil as larger utilities; with 21 percent of the nation's capacity, they account for about 23 percent of the electric utility industry's gas consumption and 17 percent of its oil consumption.

Many small utility representatives contacted in this study commented that 2,000MW may be too high a dividing point between "large" and "small" utilities. Therefore, although the study retained the statutory definition, it also devoted special attention to the 349 "very small utilities" in the range of 10 to 500MW. These utilities are somewhat more gas dependent; with 5.1 percent of total U. S. generating capacity, they consume about 9 percent of the industry's gas, but only 3 percent of its oil.

The table below indicates the relative utilization of oil and gas by utilities, compared to total national consumption of these fuels.

	Gas $x10^6$ MCF	% U. S.	Oil $x10^6$ BBL	% U. S.
Total U. S. (1979)	20,163	100	6,728	100
All Electric Utilities	3,540	17.6	548	8.1
Utilities less than 2,000MW	817	4.1	100	1.5
Utilities less than 500MW	323	1.6	20	0.3

General Impact of FUA on Small Utilities

Very few small utilities offered criticism of the FUA Title II prohibitions affecting new powerplants, nor of the ERA rules governing exemptions from these prohibitions. No small utilities appeared to be considering construction of new oil- or gas-fired powerplants, except for a small number of peaking turbines. The utilities contacted claimed that this is due to costs and uncertain supplies of these fuels and is not the result of the FUA.

The small utilities also expressed very little concern about Section 301 (b) of the FUA, which allows DOE to prohibit, by order, the use of oil or gas in certain alternate fuel capable units. Only seven small utilities have units currently being considered by DOE for proposed prohibition orders. Most small utilities do not believe any of their units would be subject to final prohibition orders because these units lack capability for burning coal.

The major impact of the FUA on small utilities results from application of the restrictions and prohibitions on gas use in Section 301(a) (the "off-gas" provisions). Many of the 132 small utilities that are heavily gas-dependent expressed doubts that any of the available options for complying with these off-gas provisions would enable them to remain economically viable.

- A utility can comply by switching to oil. Most gas-fired plants are either oil-capable or could be made so at a modest cost. However, utilities are currently paying around $2 to $3 per MMBtu for gas (based on recent contracts) while current oil prices are on the order of $4 to $6 per MMBtu. This corresponds to a price differential of 1¢ to 4¢ per KWH. Utility fuel managers apparently expect this price differential to persist or even increase in the 1990's. These small systems feel that if forced to switch a large fraction of their capacity from gas to oil, they would be placed at a competitive disadvantage with larger utilities. Also, some utilities indicated that they felt it was not in the nation's best interest to switch to oil because this would increase our imported oil consumption.

- A small utility could conceivably eliminate the need for its existing gas-fired plants by 1990 by accelerating its construction of new alternate-fueled capacity. However, most small utilities are claiming great difficulty in adding enough new capacity to meet projected load growth. They claim that building additional plants to replace existing gas-fired plants (whose useful life would normally have extended well beyond 1990) would entail a massive construction program far beyond their ability to finance and manage. Further, many utilities claim that the licensing and construction lead times would not permit the needed capacity to be brought on-line by 1990.

- o Some small utilities are attempting to meet their capacity needs by buying equity shares of new coal or nuclear projects constructed by larger utilities, or by purchasing firm power from such projects. Unfortunately, with all utilities in gas dependent regions (primarily the south central states) simultaneously facing the off-gas provisions, few such opportunities may be available.

The above three options, together with others discussed in this report (including exemptions), can assist most small utilities in meeting the off-gas provisions at an acceptable cost. Nevertheless, at the present time, these provisions are causing considerable anxiety among the small utilities. In fact, except for the off-gas provisions, the utilities have expressed practically no concern about the FUA.

Feasibility of Using Coal on a Small Scale

Many small utilities--especially those below 500MW system capacity--expressed the belief that a coal plant in the size range compatible with their systems' capacity mix and growth would be economically infeasible. This is, in part, due to unfavorable economies of scale. However, at least 12 utilities are building coal plants in the range 47 to 175MW, and many others are conducting engineering evaluations of coal plants in this size range.

One such study indicated electricity costs (capital plus operating cost) of 45, 34, and 26 mills/KWH for plant sizes of 50, 150, and 650MW, respectively. While this seems to confirm a substantial economy of scale for large coal plants, a 150MW coal plant is still economically competitive with the continued use of baseload oil plants, considering that the fuel costs alone of a plant fired by oil at the current (July 1980) price of $3.50 per MMBtu would be about 35 mills per kwh. If the price of oil rises to $5 per MMBtu, even a 50MW coal plant would be competitive.

The results of such cost comparisons are sensitive to fuel prices, cost of money, and other local conditions. However, it appears safe to conclude that coal is economically competitive with oil for baseload generation, using current technology and meeting current environmental standards, even on a scale as small as 50MW. Nevertheless, there are three common reasons why many small utilities do not consider small coal plants a viable option:

(1) The utilities are comparing coal with gas, rather than oil, and the gas price is so low that only large scale coal plants can compete;

(2) The capital costs, as well as the regulatory and technical complexities, of a coal project exceed their technical, financial, and managerial resources; and

(3) Many municipal utilities do not have a suitable site for a coal plant.

Contribution of Other Alternate Fuel Technologies

A number of small utilities have evaluated the possibility of using alternate sources other than direct coal combustion. These include wood, peat, low-Btu gas from coal, small hydro, wind, methane derived from agricultural wastes, coal-oil mixtures, used automobile tires, refuse-derived fuel, compressed air storage, and cogeneration. A few such projects have been constructed, in some cases with Federal assistance.

Many of these currently available technologies could be attractive to small utilities in the near future. Some of these technologies depend on local circumstances so that only a limited number of utilities could utilize them, and then only in limited amounts. Low-Btu gasification or coal-oil mixtures, however, have no such limitations and might be widely used by small utilities after sufficient operating experience is gained.

Small Utility Access to Large Powerplant Projects

Nearly all small utilities appear convinced that large coal and nuclear plants--400 to 1,000MW--offer the most economical source of future baseload power. A powerplant in this size range is too large for a small utility--particularly one with less than 500MW capacity--to build and operate within its own system. Many small utilities have sought equity ownership of small fractions of one or more large coal or nuclear units. This is usually accomplished either by buying small shares of projects initiated and managed by large utilities, or by joining with other small utilities (all of which are publicly owned) to form a "joint action agency" which then either develops its own powerplant projects or buys relatively large shares of utilities' projects.

The first of these concepts--joint ownership by individual small utilities--is historically the most common.

- There are 63 currently operating units, with a total capacity of 35,000MW, that are jointly owned. Fifty-eight small utilities own 36 percent of this capacity.

- There are 82 additional jointly owned generating units in various stages of planning and construction, with a total capacity of 55,000MW. Seventy-six small utilities own 43 percent of this capacity.

Joint ownership is clearly a viable and attractive option for small utilities. During the last few years, many large utilities have been receptive to small utility participation in their projects. This is due, in part, to the increased difficulty in financing large projects, and perhaps also to the outcome of antitrust reviews of nuclear projects.

The small utilities view joint ownership as having a few disadvantages--for example, lack of initiative and control, and necessity of cooperating with a much larger utility that may be competing for the same market. Furthermore, in some regions, there may simply not be enough capacity available to enable small utilities to meet their needs by purchasing shares of others' units.

To overcome these problems, some municipal utilities have joined together to form joint agencies--distinct organizational entities that can finance and build powerplants and transmission facilities to serve their members, and also negotiate the purchase of bulk power, fuel, or equity shares of facilities on behalf of their members.

Most small utilities--particularly those smaller than 500MW--consider the joint agency the most promising option for future bulk power supply. However, the joint agency as an institution is in its infancy. Currently, 31 joint action agencies exist in 23 states. All but two were established in the 1970's. Only 11 have yet entered the bond market, only two are producing power from partly-owned plants, and none are yet producing power from plants whose construction they have initiated and managed. Only seven agencies are yet committed to constructing their own plants.

The development of joint action agencies has been impeded by

- o the need for enabling state legislation, which often takes more than ten years to enact.
- o problems of coordinating commitments of a diverse set of members.
- o lack of necessary access to transmission facilities
- o opposition from investor-owned utilities, although this has decreased significantly.

All of the managers of joint action agencies were contacted during this study, and the strong concensus among them was that these problems must be resolved at the state and local level, without Federal intervention.

The contribution of joint action agencies by 1990 is expected to be 15,000MW of on-line capacity including joint ownership by agencies of projects that they did not initiate. This represents only about 12 percent of the capacity of small utilities and 2.5 percent of total U. S. generating capacity. Nonetheless, it represents a major bulk power source to 674 generating and non-generating member utilities. In the 1990's, the joint action agency could evolve into the dominant means for small utilities to develop and control their own resources.

Exemptions

Despite the progress most small utilities are making in reducing their dependence on natural gas and petroleum, many of the gas-dependent small utilities believe they will not be able to meet the off-gas provisions of Section 301 of the FUA. They state that they either must make an economically untenable shift to oil or obtain exemptions allowing continued use of gas in their existing units.

On April 9, 1979, ERA finalized its Special Rule (44 FR 21230), establishing a temporary public interest exemption under FUA for the use of gas where it could displace oil in existing powerplants. As of July 30, 1980, these exemptions were initially granted to 105 small utilities for periods of 18 months to five years. Many of the utilities contacted in this study stated that these exemptions have resulted in enormous savings to their consumers; in some cases, a halving of the cost of power. However, they are short term and cannot be used as a basis for planning.

Under Section 311(d) of the FUA, DOE must grant a temporary exemption for a powerplant that will permanently cease operation at the end of the exemption period. This exemption cannot exceed five years and cannot extend beyond the end of 1994 for gas burning units. Utilities that are willing to make such a commitment could, in effect, postpone the impact of the off-gas provisions until 1995.

Under Section 312(h) of the FUA, DOE must grant a permanent exemption to an existing baseload plant smaller than 250 MMBtu/hour fuel input capacity (roughly 25MW) if the petitioner demonstrates that the plant is not coal-capable without substantial modification or substantial derating. Many very small utilities could use this exemption to continue using gas in their small units. Some managers of very small systems expressed concern about the administrative burden of demonstrating non-coal-capability under the interim rules. The final FUA rules have responded to this concern (see following section), and a large number of petitions for this exemption can be expected.

Owners of larger generating units have a variety of temporary and permanent exemption options for existing plants that may be applicable under special circumstances. Some municipal utilities may qualify for permanent exemptions based on site limitations or environmental restrictions.

Permanent exemptions based on cost are also available (Section 312(a)), but they may be of limited interest to owners of gas-fired units. This is because the statute requires that the cost of using coal be compared with the cost of using imported oil, rather than with the much lower cost of using gas. No matter how ERA specifies the detailed "cost test," the test cannot reflect the actual economic dilemma faced by the gas-fired utility.

Almost every small utility contacted in this study complained about the complexity, time delays, uncertainties, and costs associated with the exemption process. The management of these utilities claimed that their legal, technical, and administrative staff resources were too small to enable them to develop the evidence required for the exemption. The management of the very small utilities claimed their staffs were too small even to develop an adequate understanding of the Act and the implementing regulations that affect their operations.

A utility employs an average of about one person per megawatt of capacity--a ratio that holds for the full range of utility sizes. Applying for an exemption can require as much effort for a 100MW utility as for a 5,000MW utility. Therefore, according to small utility operators, complying with the Act may place a disproportionate administrative burden on small utilities.

System Compliance Option

Title V of the FUA offers gas-dependent utilities the option of negotiating a "system compliance plan" setting limits on gas use for the entire system, rather than on a unit-by-unit basis. This option is potentially less burdensome than applying for individual exemptions. System compliance offers the advantage of

(1) replacing the statutory limits on gas consumption in the 1980's, with a more flexible approach;

(2) allowing gas consumption from 1990 through 1995 at 20 percent of the baseline level, rather than requiring total cessation of gas use in 1990;

(3) allowing limited gas use from 1995 to 2000 for intermediate and peakload generation; and

(4) allowing (if DOE approves) emergency and peakload gas use until 2005.

However, the system compliance option does require the utility, upon ERA approval, to forego permanently its right to seek exemptions under Title III, except for emergencies.

To be eligible, a utility had to submit a letter of intent by January 1, 1980. Thirty-eight small utilities submitted such letters, and on August 1, 1980, (the deadline for submission of a proposed plan) the number of eligible small utilities decreased to 30.

Some managers of small utilities indicated that the system compliance option will provide enough gas to meet their system needs. However, most of them require more gas beyond 1990 than Title V would allow, so that they could use this option only if one or more units had obtained exemptions prior to plan approval. Some managers stated that the FUA exemption process could result in their being required to make a final commitment to a system compliance plan before a pending exemption is granted or denied, thereby precluding the exemption.

Many managers of gas-dependent utilities stated that, during the years used as the baseline for determining allowable future gas use, their gas consumption was abnormally low due to curtailments. Congress apparently intended to base gas limits on a period when gas was in short supply, but may not have foreseen that many small utilities would be disproportionately affected. The differences in the way the utilities contract for gas allowed most large utilities to avoid curtailment, while many small utilities had more than half their gas supply curtailed.

There are a number of small utilities, mainly in Florida and Mississippi, who allege that their supplies were illegally curtailed. Utility responses to this study indicated that they had obtained out-of-court settlements from their gas suppliers in this matter. Thus, they foreclosed any option for future litigation on the same issue. These utilities have requested that their baseline gas consumption be restored to at least the level that would have occurred without these alleged illegal curtailments, but the legality under the FUA of such a restoration is still in doubt. DOE is currently examining this issue.

DOE ACTIONS TO ALLEVIATE COMPLIANCE PROBLEMS OF SMALL UTILITIES

As a result of information obtained in this study and in the FUA rulemaking process, DOE is taking the following actions to alleviate the compliance problems of small utilities:

- The evidentiary requirements for the permanent exemptions for existing baseload powerplants smaller than 250 MMBtu/hour (about 25MW) have been reduced to a simple certification process in the Final Rules(45 FR 53682, 53709, August 12, 1980).

- Many of the evidentiary requirements for obtaining exemptions have been simplified in the final FUA rules. For example, some exemptions are now handled by a simple certification process.

- The eligibility criteria for the exemption for "inability to obtain capital", set forth in 10 CFR 503.35, have been made more lenient for utilities under 2000MW in the final rules.

- DOE is funding a considerable number of demonstration projects involving use of alternate fuels or mixtures on a scale compatible with a small utility system.

- DOE's small hydro program is funding feasibility studies involving existing dams, many of which are in the service areas of municipal utilities.

DOE is currently searching for additional means of alleviating any disproportionate burdens FUA may place on small utilities.

In particular, DOE intends to do whatever is within its statutory power to see that small utilities that meet the substantive criteria of the Act and applicable rules for exemption are not hindered from obtaining these exemptions by excessively lengthy, complex, and costly procedures.

However, DOE believes that the problems of small utilities can ultimately be solved only by shifting to alternate fuels. Virtually all small utilities contacted in this study were in agreement that baseload generation from oil and gas would not be economically viable in the 1990's and beyond.

CONCLUSIONS

Although some of the compliance problems of small utilities can readily be corrected by procedural or regulatory changes, this study has identified a number of concerns that may be more difficult that may be more difficult to correct and may eventually require legislative action:

(1) The current method for computing a utility's baseline natural gas consumption under Section 301 may place many small utilities in a disadvantageous competitive position, due to the very uneven application of curtailments during 1974-76. The method could be redesigned to more fairly reflect normal patterns of gas usage. For example, DOE could be granted the flexibility to adjust baselines to reflect normal use. Alternatively, a utility might be permitted to use as its baseline the average of any three (not necessarily consecutive) years during the 1970's.

(2) Many small utilities apparently did not fully understand the significance of the systems compliance option, and only 38 of the 132 small utilities that are more than 50 percent gas dependent submitted letters of intent before the statutory filing date (January 1, 1980). Furthermore, the 38 utilities that did filed were required to submit compliance plans by August 1, 1980, before the final rules for exemptions for existing facilities were published and long before the outcome of their exemption petitions is known. DOE believes that system compliance, in principal, has many advantages over the unit-by-unit approach. Extension of the statutory deadline could offer more small utilities an opportunity to pursue this option.

(3) There is a question under the statute as to the circumstances under which joint action agencies and other entities representing utilities that operate in a coordinated mode may file a single system compliance plan on behalf of their members. Allowing this approach would insure that the allotted gas quantities are used in the more efficient plants, and would also encourage the development of joint action agencies.

The following additional measures for making the System Compliance Option more attractive and workable for small utilities also merit consideration:

- Increase the limits of gas consumption in the early 1990's, and then gradually decrease this limit in the mid- and late 1990's. This would permit a smoother transition away from gas and might help prevent a massive shift to oil in 1990.

- Allow an optional "package" system compliance plan for which utilities below a certain size (say 200MW) could obtain approval via a simple certification process. The plan would simply specify year-by-year limits as percentages of total gas capable generating capacity that was operational when the FUA was enacted (excluding plants that were also coal capable). No examination of actual base year consumption would be needed.

DOE is currently evaluating various alternatives for improving the system compliance option, and will analyze the impacts of such alternatives before recommending specific legislative actions.

Many of the small utilities recommended statutory changes that would constitute abandonment of part or all of the objectives of the FUA.

- Some utilities recommended that the FUA be repealed, arguing that fuel prices were already driving utilities away from oil and gas.

- Many small utilities advocated either repealing the off-gas provisions (thus treating gas and oil identifically) or at least allowing existing gas-fired powerplants to continue through their normal scheduled operating life (as would be allowed under Section 9 of S.2470, which the Senate passed on June 24, 1980).

DOE does not believe repeal of the FUA is needed to alleviate the compliance problems of small utilities, most of whom expressed their general agreement with the basic objectives of the Act.

DOE is aware of the advantages, from the viewpoint of reducing oil imports, of treating gas no more stringently than oil, especially after gas prices are degulated. However, before gas prices are fully deregulated, artifically low prices may induce utilities to use more gas than they would at prices reflecting the true marginal cost. Without the off-gas provisions, these low gas prices could reduce the incentive or utilities and regulatory agencies to expedite the shift to alternate fuels. DOE also recognizes that utility gas consumption may impact the availability of gas to nonutility users, many of whom have less ability to switch to other fuels.

Such considerations must be carefully reviewed in any reevaluation of the off-gas provisions, but DOE believes that the problems small utilities are facing in complying with these provisions can, in any case, be solved by more limited measures.

Chapter 1

Background and Design of Study

1.1 Powerplant and Industrial Fuel Use Act

1.1.1 Prohibitions [1/]

The Powerplant and Industrial Fuel Use Act (FUA) prohibits the use of petroleum and natural gas in new electric powerplants and industrial installations and prohibits the use of natural gas in existing powerplants in 1990 or thereafter. It prohibits the construction of new electric powerplants without the capability to use coal or another alternate fuel. Industrial installations, although covered by the Act, are not a subject of this report.

For purposes of the Act, a powerplant is a stationary electric generating unit consisting of a boiler, a combustion turbine, or combined cycle unit which produces electric power for purposes of sale or exchange and has a design fuel heat input rate of 100 million BTU's per hour or greater, or is in combination with other electric generating units located at the same site which have an aggregate fuel heat input rate of at least 250 million BTU's per hour. Diesel generators are not subject to the provisions of the Act.

The FUA prohibits the use of petroleum and natural gas in certain facilities. Under the Act:

(a) no new powerplant can be constructed without coal or alternate fuel capability unless specifically exempted by the Secretary of Energy;

(b) no new electric powerplant or new MFBI boiler may use petroleum or natural gas as a primary energy source unless specifically exempted by order of the Secretary of Energy;

(c) no existing electric powerplant may use natural gas as a primary energy source after January 1, 1990, or (where such powerplant used natural gas as a primary energy source in 1977) prior to that date increase its proportional use of natural gas as a primary source above 1974-1976 levels unless specifically exempted by the Secretary of Energy; and

(d) no existing electric powerplant which used coal or other alternate fuel as a primary energy source during 1977 may burn petroleum as a primary energy source in excess of the amounts used in 1977 unless granted a special permit by the Secretary of Energy.

The Act also empowers the Secretary of Energy to issues rules or orders imposing restrictions on petroleum and natural gas use in specific units of certain types. The Secretary may prohibit a specific existing electric powerplant or MFBI from using petroleum or natural gas as a primary energy source upon determining that:

(e) the unit has or previously had the technical capability to burn coal or another alternate fuel as a primary energy source;

1/ Powerplant and Industrial Fuel Use Act Annual Report. Submitted pursuant to P.L. 95-620, Section 806, Office of Fuels Conversion, Economic Regulatory Administration. March 1, 1980.

(f) the unit has the technical capability to use coal or another alternate fuel as a primary energy source, or could have such capability without substantial modification to the unit or substantial reduction in its rated capacity; and

(g) it is financially feasible for the unit to burn coal or other alternate fuel as a primary energy source.

The Secretary may prohibit by rule or by order the use of petroleum or natural gas in new MFBI's that are non-boilers. The Secretary may also prohibit the use of petroleum or natural gas beyond that needed in a mixture of oil or gas and an alternate fuel to maintain operational reliability and a reasonable level of fuel efficiency.

The Act also contains key provisions relating to coverage, administrative procedures, and other legislation.

Federally-owned or operated powerplants are subject to the FUA to the same extent as equivalent non-government facilities.

The legislation allows utility systems that are heavily dependent on natural gas to comply with the statutory natural gas prohibitions of the FUA by reducing natural gas use on a systemwide rather than on an individual unit basis. The system compliance option allows electric utility operators to file plans for approval by DOE showing their commitment to the FUA compliance.

The legislation grants the Secretary of Energy authority to issue rules and orders to implement the FUA and specifies administrative procedures for rule making.

The Act authorizes the Secretary of Energy to collect information required to implement and monitor compliance with the legislation. The Act also authorizes the Secretary to issue notices of violation of the Act and sets forth criminal and civil penalties for such violations.

1.1.2 Regulations [2/]

The FUA authorizes the Secretary of Energy to issue notices and rules to implement the legislation. Certain key regulations, such as the ones cited below, have significant impact on the implementation of the FUA.

The Administrative Rules establish procedures for the conduct of conferences and public hearings; for submission of written comments; and for the filing of petitions for exemption from rules, orders, or statutory prohibitions. These rules also identify the sanctions that are available in proceedings before ERA to implement the FUA. In general, the Administrative Rules cover the steps to be taken in the procedures used in the regulatory processes related to the FUA. (45 FR 38276, June 6, 1980, and 45 FR 53682, July 12, 1980).
The New Facilities Rules establish the requirements for a temporary or permanent exemption from the FUA prohibitions. In particular, the rules given methodologies for calculating and comparing the costs of using an alternate fuel and the cost of using imported petroleum. The rules also specify the evidence that must be submitted to support petitions for specific exemptions. (45 FR 38276, June 6, 1980)

2/ op. cit.

The Existing Facilities Rules detail the regulatory findings that must be made and the procedures for the proposal and completion of prohibition orders and rules under the FUA. In addition, the rules provide that a prohibition order may not be issued to an existing facility if the owner or operator demonstrates that the facility would be eligible for an exemption under the criteria set out in these rules. Once the prohibition orders are finished, the recipient is entitled to petition for an exemption. The Existing Facilities Rules, like those for new facilities, detail the requirements for an exemption. These rules contain methodologies for computing costs and establish requirements for submission of evidence in support of petitions for exemption. (45 FR 53682, 8/12/80)

Under the Transitional Facilities Rule, any powerplant or installation not in operation before April 20, 1977, but for which construction or acquisition began before the enactment of the FUA on November 9, 1978, is considered "new," unless the Secretary finds that the construction or acquisition could not be cancelled, rescheduled, or modified without: (1) imposing substantial financial penalties on the owners; or (2) significantly reducing electric system reliability in the case of powerplant conversions.

Under such a finding, a powerplant may be classified as "existing," and thus not be subject to the prohibitions concerning new facilities. The Transitional Facilities Rule details the definitions and procedures for eligibility, evidence, and documents required for the classification of eligible facilities as existing under the FUA. (44 FR 60690, October 19, 1979)

The Special Public Interest Gas Rule allows utilities to petition for a special temporary public interest exemption to burn natural gas in place of petroleum in existing oil-fired powerplants. This rule sets forth criteria and procedures by which owners and operators of existing powerplants may petition for this exemption. (44 FR 21230, April 4, 1979)

The System Compliance Option permits utility companies to reduce natural gas use on a systemwide basis as an alternative to compliance by specific powerplants with the FUA prohibitions on natural gas use. This rule establishes the procedures for preparation and submission of a system compliance plan as well as outlining the commitments required to carry out the plan. (45 FR 53682, August 12, 1980)

The Prohibition Against Increased Use of Petroleum Rule prohibits any existing powerplant that used coal or other alternate fuel as a primary energy source during 1977 from using petroleum as a primary energy source in any calendar year in excess of the quantities used during 1977, unless ERA issues a permit authorizing such increased use. Such permits are to be issued only where EPA or the state air pollution control agency has certified that the powerplant cannot comply with requirements of the Clean Air Act, and the appropriate state regulatory authority has certified that the use of petroleum is necessary to maintain electric service reliability. (45 FR 53682, August 12, 1980)

1.1.3 Exemptions

The Act provides for temporary and permanent exemptions from statutory as well as discretionary prohibitions. Exemptions may be granted where the petitioner demonstrates that certain physical, economic, environmental, legal, or other factors preclude the use of an alternate fuel or mixture. The burden of proof that an exemption is warranted rests with the petitioner.

Even when ERA must ultimately grant an exemption permitting the use of petroleum or natural gas, conservation measures form terms and conditions of the exemption that reduce the use of these fuels to the lowest level possible. Further, a cogeneration exemption permits new facilities to use petroleum or natural gas where the petitioner can demonstrate that the amount used by the cogenerating facility would be less than would otherwise be used in absence of the cogeneration facility by units which would not be expected to use an alternate fuel by reason of the FUA.

The Act authorizes the Secretary to grant exemptions from its prohibitions under a variety of conditions. The types of exemptions are identified in Table 1-1. Exemptions may be granted on a temporary or permanent basis. Temporary exemptions may be granted for up to five years and, in some cases, extended for an additional five years.

1.2 Statutory Authority for Study

Section 744 of the FUA (P.L. 95-620) instructs the Secretary of Energy to conduct a study of the problems of compliance with this Act experienced by those electric utility systems which have a total system generating capacity of less than 2,000 megawatts (2,000 MW). The Secretary was instructed to report his findings and his recommendations to the Congress not later than two years after the effective date of this Act.

The study concentrated on those prohibitions in the Act which would most likely present difficulties to small power systems.

1.3 Design of Study

General Objectives: The general objectives of this study, based on the prohibitions and restrictions of using natural gas as a primary boiler fuel and the population of utilities generating less than 2,000 MW, are:

(1) Inventory small utility systems subject to the Act and determine their fuel use and distributions;

(2) Identify the small utilities' own perceptions of their compliance problems with the Act;

(3) Evaluate the validity of small utilities' perceptions of these problems; and

(4) Identify and evaluate options for alleviating small utility compliance problems, consistent with the intent and purpose of the Act.

Areas of Special Emphasis: Particular attention is given to Title III, which prohibits or restricts the use of natural gas as a primary fuel in existing units. Included in these restrictions are criteria which define base period use, alternate fuel capability, fuel mixtures, and case and category prohibitions. Subtitle B of Title III establishes definitions and criteria for temporary and permanent exemptions from the prohibition were applicable.

Attention was also given to the System Compliance Option (Title V). This option permits utility companies to reduce natural gas use with a systemwide plan as an alternative to compliance by specific powerplants with the FUA prohibitions on natural gas use. The plan must contain the following elements: (1) a commitment that on or after January 1, 1990, the utility not use natural gas in its system in excess of 20 percent of the base period usage or, if lower, the minimum peak

TABLE 1-1 [3/]

GROUNDS FOR PERMANENT
FUA EXEMPTIONS

POWERPLANTS	
Existing	New
Lack of Alternate Fuel Supply	Lack of Alternate Fuel Supply
Cost of Alternate Fuels	Cost of Alternate Fuels
Site Limitations	Site Limitations
Environmental Restrictions	Environmental Restrictions
State or Local Restrictions	Lack of Adequate Capital
Cogeneration	State or Local Restrictions
Use of Certain Fuel Mixtures	Cogeneration
Emergency Purposes	Use of Certain Fuel Mixtures
Peak-Load Units	Emergency Purposes
Intermediate-Load Units	Reliability of Service
Capacity of Less than 250 Million BTU's	Peak-Load Units
Use of Liquified Natural Gas	Intermediate-Load Units

GROUNDS FOR TEMPORARY
FUA EXEMPTIONS

POWERPLANTS	
Existing	New
Cost of Alternate Fuels	Cost of Alternate Fuels
Site Limitations	Site Limitations
Peak-Load Units	Environmental Restrictions
Intermediate-Load Units	Use of Certain Fuel Mixtures
Environmental Restrictions	Future Use of Synthetic Fuels
Future Use of Synthetic Fuels	Public Interest
Use of Innovative Technologies	
Expected Retirement	
Public Interest	
Reliability of Service	

3/ Powerplant and Industrial Fuel Use Act Annual Report (Appendix B). Submitted pursuant to P.L 95-620, Section 806, Office of Fuels Conversion, Economic Regulatory Administration. March 1, 1980.

load requirements for the calendar year; (2) a commitment that from 1995 to 2000 the utility will not use natural gas as a primary energy source; and (3) a commitment that on or after January 1, 2000, the utility will not use natural gas in its system at all.

Compliance Options Examined: The 1990 cut-off date for natural gas presents a time constraint which some small utilities believe they may not be able to meet. A number of the issues involved include cost and capability for fuel conversion, front-end schedules for new replacement facilities, current long-term gas contracts (Section 731) and availability of alternate fuels. This report cites compliance options which may be of interest to small utilities and within the realm of possibility with regard to alternate fuels.

Options examined include:

(a) Conversion to oil;

(b) Conversion to coal (includes new facilities);

(c) Construction of new facilities based on coal or other alternate fuels;

(d) System Compliance Option;

(e) Temporary and/or Permanent Exemptions; and

(f) Purchase power and/or joint action/ownership participation.

1.4 Conduct of Study

1.4.1 Sources of Information

In order to focus directly on the appropriate compliance problems met by these utilities, the study identified those small systems which are most heavily dependent on natural gas as a boiler fuel. It was felt that these systems would be the most heavily impacted and thus a reasonable are of interest.

Individual contact with as many small utilities as possible was made since these contacts were considered an extremely important means for understanding the nature of compliance issues confronting small generating utilities. In addition to discussions at annual meetings, system compliance meetings and other conferences, a public meeting was held in Dallas, Texas, following a Federal Register notice of inquiry and request for information on April 17, 1980. Following the meeting, individual letters soliciting comment and opinion were sent to 296 small utilities which had not been previously contacted. A copy of the letter of inquiry and the Federal Register notice is included as Appendix E. While many utilities commented on similar compliance problems, they varied in their interpretation of the statute and the regulations as well as their compliance strategies. A discussion of these responses is included in Chapter 4 of this report.

1.4.2 Case Studies

Given the total population of small utilities with capacities between 10-2,000 MW, the selection of significant case studies was based on geographic location, ownership, and fuel use because natural gas-fired systems could expect to have greater compliance problems with the Act.

Based on the selection criteria mentioned above, 435 small utility systems (see Chapter 2) were screened. There were 25 candidate systems initially identified. Telephone contact was made with each candidate system and, based on these contacts, the selection list was reduced to 15 small utilities. From this final list, ten case studies were selected (Table 1-2).

TABLE 1-2
SMALL UTILITY CASE STUDY

ERA REGION	SYSTEM	1979 GENERATING CAPACITY (MW)	1979 FUEL USE (%)	OWNERSHIP	LOCATION
24	Farmington	36	100% natural gas	Municipal	New Mexico
24	Lamar	32	94% natural gas 6% oil	Municipal	Colorado
5	Dover	134	76% natural gas 24% oil	Municipal	Delaware
18	Wolverine Electric Cooperative	77	100% natural Gas	Cooperative	Michigan
21	Central Telephone and Utilities	437	89% natural gas 11% oil	IOU	Kansas and Colorado
28	Sierra-Pacific Power Company	556	31% oil 67% natural gas 2% hydro	IOU	Nevada
7	Vero Beach	130	31% natural gas 69% oil	Municipal	Florida
22	Lubbock	252	100% natural gas	Municipal	Texas
22	Western Farmers Cooperative	719	100% natural gas	Cooperative	Oklahoma
23	West Texas Utilities	1,051	100% natural gas	IOU	Texas

The case studies involved three steps to completion. First, extensive background information was developed based on DOE data and personal contact with each utility. On-site interviews were completed with each utility to complete the second step. The third step involved the analysis and write-up of conclusions of each case study.

Natural gas-fired small utilities are concentrated in the Midwest and Southern plains area. Of the 132 small utilities which have more than 50 percent gas-fired generation, 62 are located in Texas, New Mexico, Colorado, Oklahoma, and Kansas.

For other regions of the country, other case studies were selected based on geography and current fuel use. Municipal utilities in Florida (Vero Beach) and Delaware (Dover), as well as an investor-owned utility in Nevada (Sierra-Pacific Power Company), appeared to be representative of small power systems with typical fuel mixes and generation plans for their region of the country, yet still liable for compliance to the FUA. Table 1-2 lists the ten case studies used in this report. The utilities are described by capacity, fuel use, ownership, and location.

Eight of the case studies were selected with the rationale and criteria discussed above. The ninth (Western Farmers Cooperative) and tenth (West Texas Utilities) case studies were the result of the respective utilities developing and providing ERA with descriptions of their systems and information relevant to the impact of the FUA on their operation and their interpretation of certain compliance strategies.

1.4.3 Timing

Compliance with the provisions of the Act is governed by the issuance of rules to implement regulatory options.

Final Administrative Rules covering procedures and conduct for public hearings, filing for petitions of exemption or statutory prohibitions, and submittal of written comments were published in the Federal Register on June 6, 1980, effective August 5, 1980. (45 FR 38276)

Final Rules pertaining to the use of petroleum and natural gas in new electric powerplants were published in the Federal Register on June 6, 1980 (45 FR 38276)

Final Rules for Existing Facilities were published on August 12, 1980. (45 FR 38276)

On April 4, 1979, a Special Rule for Temporary Public Interest Exemptions was published in the Federal Register. This rule allowed temporary exemptions for the use of natural gas where it would displace oil.

The Interim Rule for the System Compliance Option was published in the Federal Register on June 20, 1979 (44 FR 36002). Under the provisions of the Act and this rule, utilities interested in obtaining a system compliance option were required to submit a compliance plan by August 1, 1980. The Final Rule was published on August 12, 1980 (45 FR 53682)

Chapter 2

Characteristics of Small Utilities

2.1 Small Utility Systems

The following information characterizes small utility systems as defined in Section 744. For purposes of this study, relevant to the provisions of the Fuel Use Act (FUA) for oil and gas burning powerplants, the systems are classified and grouped in several categories. The primary sources or information for identifying small utility systems were the Department of Energy, Energy Information Administration (EIA), 1/ The Electric World Directory of Electric Utilities, and clarifying data from utility trade associations.

2.2 Small Utility System Characteristics

To determine how many and to what extent small utility systems will be impacted by the FUA, systems were identified by size (MW of generating capacity) and fuel use (percent of capacity fired with natural gas). They are also classified by system ownership type (municipal, cooperative, investor-owned) because this influences the financing mechanisms for the system.

2.2.1 Generating Capacity

Table 2-1 summarizes the generating capacity distribution for 988 U. S. electric utilities, identifying the number of systems by size, capacity, and percent of the nation's total capacity. There are 84 electric utilities with system capacities over 2,000MW. Of the remaining 904, 52 percent (469) are systems with less than 10MW.

Because the FUA exempts power generating units smaller than 100MMBtu/hr, the 469 small utility systems in the 0 to 10MW generating capacity range were not included for further study. These utilities provide less than 0.3 percent of the total generating capacity and less than 0.1 percent of the total power generated. There did not appear to be any severe ramifications on these small systems from the FUA.

Of the remaining 435 small utilities, 349 are in the 10-500MW generating range and provide almost five percent of the nation's total capacity, 3.7 percent of the net power generated in 1979. The remaining 86 small utility systems range between 500-2,000MW generation and provide 17 percent of the net power generated; comprising 15.7 percent of the nation's total capacity.

There are 17 small utilities that have between 1,500-2,000MW installed capacity. A review of these largest of the small systems showed that they were either already predominantly coal-fired systems, or were planning, constructing, or participating in new coal-fired and nuclear generation. New capacity additions would put them over 2,000MW in capacity by 1990. These utilities thus affected were not given priority for this study.

2.2.2 Fuel Use

Small utility systems have an annual fuel demand which includes coal oil, hydro, and uranium, in addition to natural gas. Totally, small utilities consume 16 percent of the annual consumption of coal by utilities;

1/ Inventory of Powerplants in the United States, U. S./DOE, EIA, December 1979; and computer listings based on utility submittals of Form 4 of the Department of Energy.

Table 2-1: Size Description of Electric Generating Systems

SIZE CLASS	NUMBER OF UTILITIES	TOTAL CAPACITY (MW)	PERCENTAGE OF TOTAL
OVER 2,000 MW	84	473,700	79.1
1,500-2,000 MW	17	29,251	4.9
1,000-1,500 MW	31	37,574	6.3
500-1,000 MW	38	27,179	5.0
200-500 MW	47	14,403	2.4
100-200 MW	39	5,644	0.9
50-100 MW	61	4,347	0.7
25-50 MW	68	2,358	0.4
10-25 MW	134	2,163	0.4
< 10 MW	469	1,717	0.3
TOTAL	988	598,336	100

Table 2-2: Size Description of the Electric Generating Utilities Using Natural Gas (1979)

SIZE CLASS	NUMBER OF UTILITIES	TOTAL CAPACITY (MW)	BCF (ANNUAL)	NATURAL GAS %
OVER 2,000 MW	66	363,766	2,722	77.0
1,500-2,000 MW	8	14,159	83	2.3
1,000-1,500 MW	17	20,801	219	6.2
500-1,000 MW	18	14,919	191	5.4
200-500 MW	27	8,606	133	3.8
100-200 MW	21	2,842	51	1.5
50-100 MW	30	2,081	37	1.0
25-50 MW	43	1,459	25	0.7
10-25 MW	77	1,284	15	0.4
< 10 MW	--	--	60	1.7
TOTAL	307	429,917	3,540	100.0

Table 2-3: Small Utility Systems
Natural Gas and Oil Usage

SIZE CLASS	NUMBER OF SYSTEMS OVER 50% CONSUMPTION (ANNUAL) Natural Gas	Oil
1,500-2,000 MW	2	4
1,000-1,500 MW	4	3
500-1,000 MW	7	2
200-500 MW	10	9
100-200 MW	13	7
50-100 MW	20	3
25-50 MW	27	8
10-25 MW	49	36
TOTAL	132	72

representing eight million short tons (1979). Small utilities also use 17 percent of the total annual utility consumption of oil, representing approximately 100 million barrels per year. Among the 435 small utilities, there is a tremendous spread of fuel use by each system. Several very small systems (less than 50 MW) use coal and many are dependent on oil-fired generation, with some capability to coal. Several are completely based on hydro power.

Natural gas use by electric generating utilities is summarized in Table 2-2. Small utility systems between 10-2,000 MW used 20.3 percent of the total gas used for electric generation in 1979; the largest gas consumption occurring in the 1,000-1,500 MW range; the greatest number of gas burning utilities are in the 10-25 MW range. There are 132 small utility systems which use, or are heavily dependent on, natural gas as a primary fuel. Table 2-3 summarizes the individual size of these systems with the percent of natural gas used for generation. These small utilities represent only 30 percent of the systems between 10-2,000 MW generating capacity. There are 99 of these small utilities which are smaller than 500 MW capacity. Of these 132 small utility systems identified above, 113 have over 70 percent of their capacity in natural gas-fired units. These systems represent 26 percent of the small utilities between 10-2,000 MW capacity. These 113 small utilities consumed 17 percent of the natural gas used by electric generating utilities in 1979.

2.2.3 Geographical Distribution

Table 2-4 shows the geographical location of small utility systems, using natural gas, by electric reliability region. A map of these regions is presented in Figure 2-1. The location of these systems is significant in that they are primarily located in natural gas producing areas. Several of the small utilities, in fact, have ownership in gas fields near their facilities (SWPP region). Many small utilities in the Upper Midwest are close to main natural gas pipelines (MARCA region).

Small utilities located in the eastern third of the United States show a mixture of fuel use between coal, oil, and natural gas. Those relying on oil as a boiler fuel are primarily in the Northeast and Southwest. Small utilities in the North Central and Middle Atlantic states are predominantly coal-fired, but there are a few natural gas-fired small systems scattered throughout the areas. Most of these have plans to build or purchase portions of new coal-fired generation before 1990. Oil burning small utilities in the West are primarily in Southern California. There are not many small utility systems in the Mountain states. The few that are have coal and oil as the predominant boiler fuel with increasing emphasis on coal.

2.2.4 Ownership

Most small utilities are municipally owned. Of the 904 small utility systems initially identified, 70 percent are municipals, 8 percent rural cooperatives, 14 percent investor-owned, and 6 percent Federally owned, and 2 percent are state operated facilities. The federal and state systems are almost entirely hydro based and are of little interest to this study.

Of the 435 small utility systems in this study, 52 percent are municipal, 9 percent are cooperative, 23 percent are investor-owned, and 16 percent are government-owned. Table 2-5 describes small utility ownership by generating capacity.

Among the 132 small utility systems which are most heavily dependent on natural gas, 80 percent are municipally-owned, 8 percent are rural cooperatives, and 10 percent are investor-owned utilities.

Table 2-4: Small Utility Systems By Reliability Region

SIZE	ECAR	MAIN	MAAC	MARCA	NPCC	SERC	SWPP	ERCOT	WSCC	ASCC	HICC
1,500-2,000 MW	2	1	1	0	4	2	1	2	4	0	0
1,000-1,500 MW	6	2	0	3	7	1	3	1	8	0	0
500-1,000 MW	2	2	1	7	4	6	5	1	10	0	0
200-500 MW	2	2	2	4	1	8	10	4	12	2	0
100-200 MW	3	2	3	7	6	5	8	1	2	1	1
50-100 MW	9	5	1	10	4	2	17	2	7	2	2
25-50 MW	9	11	1	11	7	5	16	3	2	3	0
10-25 MW	16	16	0	35	9	5	30	7	12	3	1
TOTAL	49	41	9	77	42	34	90	21	57	11	4

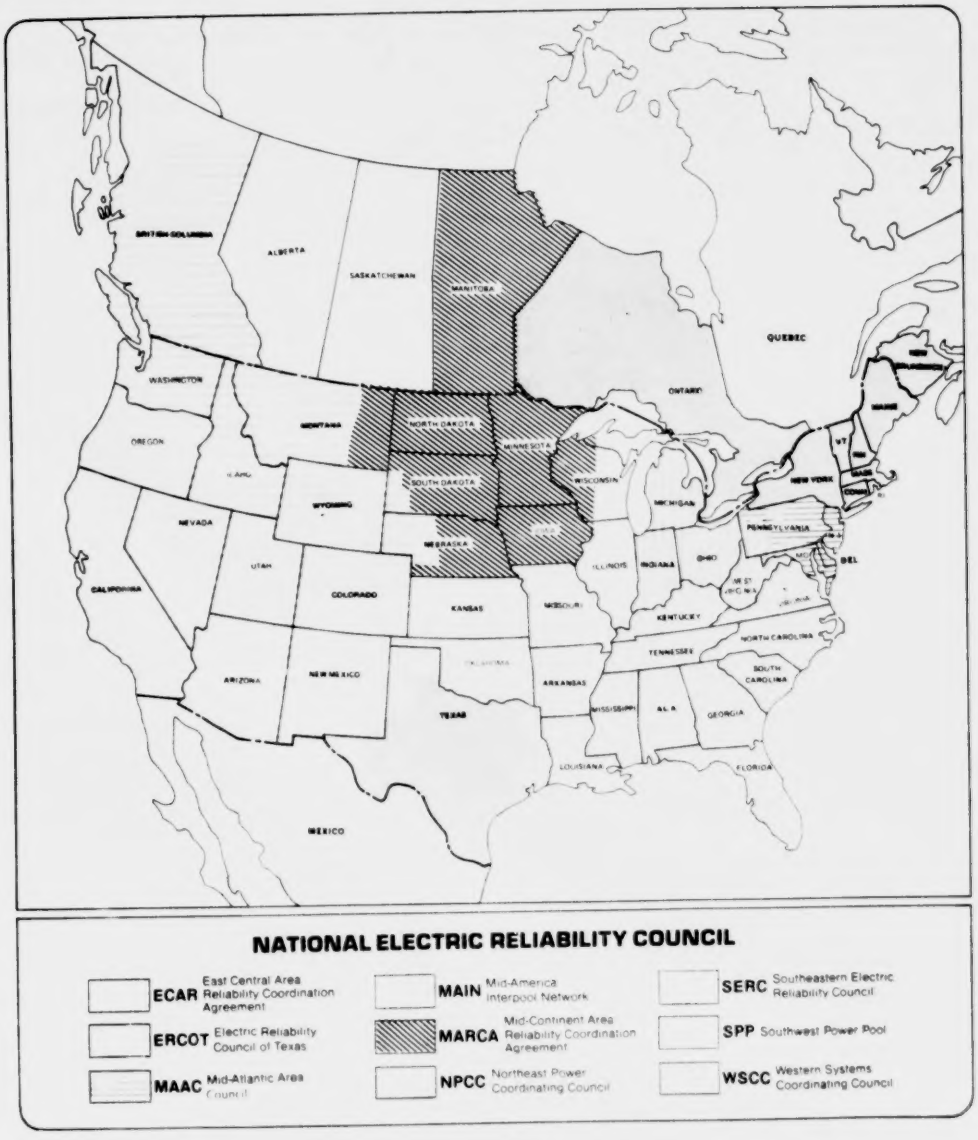

FIGURE 2-1

Source: National Electric Reliability Council: 1977 Annual Report.

Table 2-5: Small Utility System Ownership

SIZE	INVESTOR OWNED	RURAL COOPERATIVE	MUNICIPAL	PUBLIC POWER DISTRICT	OTHER
1,500-2,000 MW	9	1	2	2	3
1,000-1,500 MW	25	1	1	0	4
500-1,000 MW	18	9	6	2	3
200-500 MW	11	9	15	0	12
100-200 MW	9	0	24	1	1
50-100 MW	11	10	28	3	9
25-50 MW	8	2	45	3	11
10-25 MW	8	6	106	1	15
TOTAL	99	38	228	12	58

Chapter 3

Problems and Issues

This chapter discusses the perceptions of compliance problems confronting small utilities as identified by representatives of small utilities. Chapter 4 discusses small utility compliance strategies based on the problems encountered. Chapter 6 discusses alternative technology options related to compliance strategies, and Chapter 7 outlines regulatory alternatives.

The problems cited by the small utilities appear to cut across the full range of "small utilities" from 10 to 2,000MW, but those smaller than 500MW were particularly concerned about the problem of economies of scale associated with generating technologies based on alternate fuels. However, small utilities in the 500 to 2,000MW size range mentioned most of the same compliance problems and strategies as the "very small utilities" of less than 500MW.

Although a number of the Fuel Use Act (FUA) problems and issues cited by small utilities would seem to impact larger utilities as well, the small utilities believe they are affected disproportionately because their compliance options are more limited.

3.1 Effects of FUA on Planning

At least two dozen small utilities have already investigated technological alternatives to reliance on natural gas and oil prior to the passage of the FUA in 1978. One utility indicated that as early as the late 1960's, the lack of an assured gas supply caused it to construct a mine-mouth coal-fired plant (Empire District).1/ The gas "crunch" and the Arab oil embargo of the 1970's prompted utilities to pursue alternatives--principally joint ownership of nuclear and coal-fired units--which would render their systems less vulnerable to fluctuations in oil and gas supplies and prices (see Chapter 5).

Table 3-1 presents a compilation of compliance problems and strategies as related by small utilities contacted and/or responding to requests for information by ERA. More than 70 small systems are listed and range in size from 11 to 1,655MW representing a sample from 26 states. The key to Table 3-1 identifies the problems and strategies associated with each small power system.

3.1.1 General Constraints

Small utilities generally perceived the following limitations on their FUA compliance options:

- Lack of professional manpower to deal with regulations and to formulate compliance strategies;
- Regulatory costs of compliance associated with governmental processes, filing fees, and the necessity of hiring consultants; and

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1/ Wherever a utility's name is cited, it is based on written responses (Appendix H), a case study (Appendix A), or, in some cases, from the record of system compliance meetings (General File-System Compliance Option) held in the spring of 1980, which are in the public file in the Office of Public Information, Economic Regulatory Administration, U. S. Department of Energy, 2000 M Street, N.W., Washington, D. C. 20461.

TABLE 3-1
FUA COMPLIANCE PROBLEMS AND STRATEGIES
CITED BY SMALL UTILITIES*

UTILITY	TYPE	SIZE	FUELS	COMPLIANCE PROBLEMS	COMPLIANCE STRATEGIES
Arizona					
Tucson Electric Power Company	I	863.5	Gas/oil/coal	4,6,8,9,10	1,8,10,13
California					
Burbank	M	250	Gas/oil	6,7,8,9	3,8,9,13
Glendale	M	306	Gas/oil	1,2,6,10,13, 14	13
Imperial Irrigation District	O	391	Oil/gas/hydro	1,2,6,8,14	6,8
Sierra Pacific Power Company (California and Nevada)	I	566	Gas/water/oil	1,4,6,15	4,7,9
Colorado					
Colorado Springs	M	547	Coal (86%)/gas Oil (14%)	16	1
Lamar	M	36.72	Gas/oil	1,2,4,5,6,9	3,8,10,13
Trinidad	M	11.5	Coal/gas/oil	8	2
Connecticut					
Wallingford	M	22.5	Oil	1,6,13,14	13
Florida					
Florida Municipal Power Agency (joint agency)	M			1,2,7	13
Homestead	M	53	Oil (diesel)	1,2,7,10,13, 14	6,8
Gainesville	M	245	Gas/oil	1,2,4,5	1,7,8,9, 10,13
Lakeland, Tallahassee, Vero Beach, Fort Pierce, Utilities Authority, Lake Worth Utilities Authority, New Smyrna Beach Utilities Commission, Sebring Utilities Commission	M	Varied	Gas/oil	1,2,5,6,7,8, 10,13,14	1,2,5,8,9, 10,12
Orlando	M	726	Gas/oil	1,2,5,7,13, 15	8,13
Illinois					
Highland	M	11.5	Gas/oil (diesel engine)	6,7,15	6

TABLE 3-1 (Continued)

UTILITY	TYPE	SIZE	FUELS	COMPLIANCE PROBLEMS	COMPLIANCE STRATEGIES
Iowa					
Interstate Power Company	I	903	Coal (85%/ oil/gas)	16	14
Iowa Power and Light	I	1,331	Coal/oil/gas	16	14
Iowa-Illinois Gas and Electric Company (Iowa and Illinois)	I	530	Coal/nuclear/ oil/gas/ hydro	1,2,6	1,3,13
Spencer	M	23.4	Jet fuel	2,6	10
Kansas					
Central Telephone and Utilities (Western Power Division)	I	406.3	Gas/coal/oil	1,2,4,5,8, 9,10,15	4,6,8,9, 10,13
McPherson	M	216.4	Gas/oil	1,2	1,6
Ottawa	M	25.25		1,2,3,6,7, 9,10	13
Pratt	M	25.25		5,6,13	13
Sunflower Electric Cooperative	C	253.4		5,15	9,13
Louisiana					
Houma	M	110.2	Gas	1,2,6,7,8, 11	10
Lafayette	M	372.9	Gas	10,11	8
Morgan City	M	80.61		1,2,5,9, 10,11	13
Ruston	M	83.48	Gas	5,15	8
Massachusetts					
EUA Service Corporation (holding association)	I	Varies	Oil/jet fuel	1,2,4,7,8, 13,15	7,8
New England Gas and Electric Association	I	1,087	Oil	6	7,8
Michigan					
Detroit	M	204	Oil/gas	1,4,8,9	13
Wolverine Electric Cooperative	C	79.7	Gas/oil	1,2,8	1,8,10
Zeeland	M	23	Gas/oil (diesel)	N/A	N/A
Upper Peninsula Power	I	85	Coal/oil	12,13,14	14
Minnesota					
Minnesota Power and Light Company	I	1,655	Oil/coal	2,4,8,15	10,13

TABLE 3-1 (Continued)

UTILITY	TYPE	SIZE	FUELS	COMPLIANCE PROBLEMS	COMPLIANCE STRATEGIES
Mississippi					
Clarksdale	M	63	Gas/oil	1,2,5,11, 12,13	8,9,10
South Mississippi Electric	C	566	Coal/gas/oil	1,6,9,10	1,2,8,13
Yazoo City	M	29	Gas	1,2	11,13
Missouri					
Empire District Electric Company	I	475.9	Oil/coal/hydro	3,5,15	7,8
Fulton	M	32.5	Oil/gas	4,6,11	6
Columbia	M	120	Gas/oil	6,8,11,14	1,11,13
Montana					
Montana Power Company	I	1,100	Water/coal/oil	2,3,5,6,11	8
Nebraska					
Lincoln	M	109.7	Nuclear/coal/ hydro	2,4,11,16	1,6,7,8, 10,13
New Hampshire					
Public Service Company of New Hampshire	I	1,247		9,15	14
New Jersey					
Atlantic City Electric	I	1,433	Coal (3%) nuclear (23%)/ oil (35%)/ gas (5%)	16	14
New Mexico					
Public Service of New Mexico	I	1,023	Gas/coal	16	7
New Mexico Electric Service Company	I	184	Gas	16	6,10
Farmington	M	34	Gas/oil	1,2,6,7,8, 9,11	3,5,8,9, 10,13
Lea County Electric Cooperative, Inc.**	C	69.5	Gas/oil	1,2,6,9,10	3,9,10
Plains Electric G&T	C	52	Gas	2,5,6,11	6,7,9,10, 13
New York					
Central Hudson Gas and Electric Corporation	I	930	Gas/oil/hydro	4,6,8,15	2

TABLE 3-1 (Continued)

UTILITY	TYPE	SIZE	FUELS	COMPLIANCE PROBLEMS	COMPLIANCE STRATEGIES
Ohio					
Lebanon	M	20	Oil	6,7,10	6,11
Orrville	M	64	Coal/oil	6,8,11	11,13
Columbus	M	46	Coal	16	14
Oklahoma					
Western Farmers Electric Cooperative	C	718	Gas/waste/ heat/coal/ oil	3,8	8,9,13
Texas					
Denton	M	201	Gas	2,4	7,12
Brazos Electric Power Cooperative, Inc.	C	490	Gas/oil/hydro purchases	1,5,6,11	1,6,8,9, 10
El Paso Electric Company	I	976.5	Gas/oil	1,2,6,11,15	1,8,9
Lubbock	M	235	Gas/oil	1,2,6,7,11, 13,14,15	6,8,13
Medina Electric Cooperative, Inc.	C	75	Gas/oil	16	6,8
South Texas Electric Cooperative, Inc.	C	47.5	Hydro	16	6,8
Texas Municipal Power Agency (joint agency)	M	750	Coal/gas/oil	4,6,11	8,9,13
West Texas Utilities Company	I	1,051	Gas	6,9,10,11	8,10
Vermont					
Burlington**	M	58	Gas/coal/oil	2	4
Washington					
Washington Water Power Company	I	1,029.4	Water/gas/oil	6,7,11,13, 14	1,5,7,8, 13
Wisconsin					
Madison Gas and Electric Company	I	619.2	Coal/oil/gas	3,8,11	13
Marshfield	M	39	Coal (75%) gas/oil	1,2,3,4,5, 6,7,14, 15	1,6,8,10, 13

TABLE 3-1 (Continued)

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* Based on case studies and correspondence in Appendices A and H, except as noted.
** Based on interview/meeting.

KEY

A. TYPE

Municipal - M Investor-Owned - I Cooperative - C Other - O

B. COMPLIANCE PROBLEMS

1. Lack of professional manpower to deal with regulations and pursue compliance strategies.
2. Regulatory costs of obtaining exemptions, system compliance plans, and formal interpretation.
3. Time limitations of the FUA.
4. Uncertainties in the FUA implementation or interpretation by ERA.
5. Low usage of gas during base period.
6. Existing unit design (costs) or operational characteristics.
7. Economies of scale of alternative technologies (cost of new capacity).
8. Environmental restrictions.
9. Site limitations (acreate, water availability, etc.).
10. Unavailability of alternate fuels (including coal transportation costs).
11. Availability of natural gas and/or oil.
12. Difficulties purchasing power.
13. Difficulties obtaining access to joint utility projects.
14. Difficulties obtaining access to transmission
15. Difficulties obtaining necessary capital.
16. None stated.

C. COMPLIANCE STRATEGIES

1. Apply for temporary public interest exemption.
2. Implement fuel conversion - coal.
3. Implement fuel conversion - synfuels.
4. Implement fuel conversion - solar, wood.
5. Convert for cogeneration.
6. Contract purchase of base load power from another utility.
7. Plan construction of new base load unit using alternate fuel.
8. Consider construction of or purchase of capacity share in jointly-owned base load unit using alternate fuel.
9. Submit system compliance plan.
10. Apply for permanent and/or temporary exemptions (other than temporary public interest exemption).
11. Propose sale or dismantlement of system.
12. Plan to retire unit in 1990.
13. Recommend amending or appeal of the FUA to exempt system or unit.
14. None stated.

- Economies of scale of plant technologies based on alternate fuels, including the economies of scale of conversion to alternate fuels.

3.1.1.1 Lack of Professional Manpower

Twenty-six percent of the small utility responses cited lack of in-house manpower as a serious problem in complying with the FUA. Some suggested that the FUA placed a disproportionate compliance burden on them, because they did not have appropriate or sufficient in-house personnel (attorneys, engineers) to deal with the "complex ERA regulations" implementing the FUA and to formulate appropriate compliance strategies (Lamar, Plains Electric, Farmington, McPherson, Marshfield). At least one utility indicated that it had missed the system compliance option deadline of January 1, 1980, because it was not able to successfuly track the regulations (Lubbock).

The size of a utility's staff is roughly proportional to the capacity of the system. For example:

- Central Illinois Light Company has 1,557MW and 1,500 employees.
- The City of Zeeland, Michigan, as 23MW and 20 employees.

In fact, utilities of all sizes employ, on the average, one person per megawatt. Therefore, there is no doubt that small utilities have less manpower available to deal with complex regulatory procedures. Nevertheless, there is evidence that some small utilities have overcome this disadvantage.

It was clear in the case studies that much of the useful information about FUA options had come to small utility operators from secondary sources and not from internal analysis of the Act and regulations. The American Public Power Association (APPA), Edison Electric Institute (EEI), National Rural Electric Cooperative Association (NRECA), and informal contacts with other utilities were variously cited as sources of interpretation and strategy (Lamar, Farmington, Central Telephone, Wolverine, Brazos, Muscatine, Orrville, South Mississippi). The professional associations have been active in disseminating information about the FUA to their memberships and in lobbying for legislative and regulatory reforms. Independent technical and legal consultants have also made substantial contributions. In addition, contacts with DOE staff have contributed to learning about interpretation of the regulations and specific intents of the Act (Vero Beach, Austin, West Texas, Orlando, Bryan, St. Joseph, Oglethorpe, Brazos).

While the lack of staff and budget has been cited by many small utilities, some have, nonetheless, petitioned ERA for various temporary exemptions to the Act. 2/ Small utilities have also applied for the System Compliance Option under Title V of the FUA. 3/

One other means by which small utilities can overcome a staff and/or budget limitations is to combine efforts to obtain technical or legal assistance for regulatory issues. A number of small utilities in Florida stated that the approach was effective for them.

Nevertheless, there is little doubt that dealing with Federal regulations presents an awesome burden to those who are operating on a limited budget, governed by a city council or small board of directors, and have only limited capacity for technological change with an existing system. These small utility operators depend mainly on their respective trade associations to keep them apprised of current and pending energy legislation and regulations. However, some small utility operators have stated that they cannot keep up with all the notices and announcements these organizations send them. Annual conferences and technical committee meetings also inform the industry of new regulatory developments, although not always in time to be useful in meeting the schedule requirements of a regulation (e.g., System Compliance Option).

2/ Arkansas Electric Cooperative, Arkansas-Missouri Power, Atlantic City, Austin, Bluffton, Brazos, Brownsville, Bryan, Burwell, Cambridge Electric, Central Hudson, Central Louisiana, Central Nebraska, Central Telephone, Chanute, Clarksdale, Cleveland, Coffeyville, Colorado Springs, Columbia, Crete, Danville, Delmarva, Detroit, Dover, Easton, El Paso, Empire District, Estherville, Fairbury, Fort Pierce, Gainesville, Glendale, Grand Island, Greenwood, Gulf Power, Hamilton, Hastings, Holyoke, Homestead, Hutchinson, Idaho Power, Imperial, Independence, Iowa Power, Iowa-Illinois, Jackson, Jonesboro, Kansas City, Kennett, Kissimmee, Lafayette, Lake Worth, Lakeland, Larned, Lincoln, Lower Colorado, Madison Gas, Malden, Marshall, Marshfield, McPherson, Memphis, Minden, Montana Power, Mora, Narrangansett Electric, Natchitoches, Nebraska Public Power, Nevada Power, New Bedford, New Orleans, Orange and Rockland, Orlando, Ottawa, Owatonna, Piggott, Plaquamine, Red Cloud, Reedy Creek, Rensselaer, Rochester, Ruston, Savannah Electric, Sebring, Shelby, Sierra Pacific, Sikheston, Sleepy Eye, Southern Indiana, South Mississippi, Spring Valley, Springfield, St. Cloud, St. Joseph, Stillwater, Sunflower, Tallahassee, Taunton, Tecumseh, Tri-State, Tucson, Vero Beach, Washington Water Power, West Texas, Wolverine, Worthington, and Yazoo City.

3/ Austin, Brownsville, Bryan, Central Nebraska, Central Telephone, Clarksdale, Denton, El Paso, Farmington, Fort Pierce, Gainesville, Garland, Grand Island, Greenville, Lafayette, Lakeland, Lake Worth, Lea County, Montana-Dakota, Nebraska Public Power, New Smyrna Beach, Orlando, Plains Electric, St. Joseph, Sebring, Sunflower, Tallahassee, TMPA, and Vero Beach.

Despite the efforts of trade associations, Federal Register Notices, DOE efforts towards notification and professional conferences, the costs of pursuing governmental processes, hiring independent consultants, and interpreting legal solutions, can be burdensome to small utility systems. These systems are operated with minimal staffs headed by a general manager or superintendent with both administrative and operational responsibilities, leaving little time available for additional responsibilities.

3.1.1.2 Uncertainties in Implementation

Uncertainty about the final regulations has sometimes led to inaction (Lubbock). Small utilities assert that uncertainties are especially onerous for them because of their lack of professional manpower and the costs of pursuing lengthy government processes to what may be a fruitless conclusion (TMPA). They assert that small utilities simply cannot afford mistakes in the regulatory process which may be absorbed more easily by larger utilities.

3.1.2 Compliance Constraints-Existing Units

Virtually every small gas-fired utility contacted expressed concern over Section 301(a) of the Act, which prohibits the use of natural gas after 1990 in facilities that existed in 1978. Many of these facilities are less than 15 years old (Brazos, Burbank, Clarksdale, Columbia, Denton, Dover, El Paso, Fulton, Horma, Lafayette, Lamar, Lubbock, Missouri Utilities, New England Electric, Plains Electric, Ruston, Sierra Pacific, South Mississippi, Sunflower, Yazoo City, Zeeland). For those systems with relatively new units, the loss of investment in a facility retired prematurely would be economically and technically difficult for the system.

No small utilities that responded expressed concern about Section 301(b), under which the Secretary of Energy can issue an order to prohibit the use of oil or gas in a specific coal capable plant. Apparently, none anticipated receiving prohibition orders because they did not have coal capable plants. Therefore, impediments perceived by small utilities to compliance for existing units were examined in the context of Section 301. The issues raised included unit design, site restrictions, availability of natural gas, low base period usage of natural gas, environmental concerns and site limitations.

3.1.2.1 Fuel Capability

Small utilities contacted during the case studies and the system compliance meetings presently obtain their base load power from gas-fired steam turbine generators with fuel oil back-up capability (Farmington, Lamar, Central Telephone-Western Power Division, Lea County). Some utilities studied have additional units which are either exempt from the prohibitions of the Act (gas- or oil-fired diesel engines) or which use alternate fuels (hydraulic turbine generators). These additional units, however, usually represent a small percentage of the system capacity and are retired or used only for peaking, standby, and reserve.

Most utilities perceived their economically rational conversion options to be limited to coal or oil, although some small utilities are investigating the feasibility of other alternatives (see Section 6.2.1).

Gas-fired steam turbine generators are rarely converted to coal without replacing the boilers. Lamar Utilities has investigated the feasibility of replacing its 25MW gas-fired boiler with a 20MW coal-fired boilers and determined that the conversion would cost $19.3 million (1981 dollars) without sulfur dioxide pollution control. Although there would be savings in fuel cost that would partially offset the capital cost of this conversion, the net result would be an increase in the cost of generation of $0.01328 per KWH with a 20 percent decrease in capacity. Lamar rejected the coal conversion option as too costly, particularly when compared with other options (joint ownership, syngas, cogeneration). A description of Lamar's options are detailed further in Appendix A of this report. Other small utilities have studied the feasibility of conversion to coal and found the cost to be prohibitive (Central Hudson, Lubbock, Brazos, Tucson Electric, Yazoo, Minnesota Power, Empire District, Spencer, Columbia, Lea County).

A few small utilities contacted had units which were capable of burning three fuels: gas, oil, or coal (Central Telephone-Colorado Division, Lincoln, Dover). Several of these units presently burn gas or oil because of environmental restrictions. One utility proposed to convert one of the units to coal (Central Telephone). However, nearly all gas-fired units with alternate fuel capability are restricted to oil as a secondary fuel. Five small utilities stated that they were not even able to use oil as an alternate to gas.

Utilities with gas/oil capable units often operate under interruptible gas contracts and have adjusted to take advantage of cost differential between gas and oil in the past. Presently, these utilities prefer to use gas a primary fuel and believe that gas will be in plentiful supply in the future. In addition, the cost of gas at the present time is less than the cost of oil (Section 3.1.2.3). Many utility operators questioned the prudence of switching from gas to oil, based on gas supply and the cost of oil (see Section 6.1.3.3).

Most oil-fired units are not coal capable. In some cases, utilities stated that coal conversion was possible but too costly at the present time (Central Hudson, EUA, New England). One company stated that regulatory lag, economic recession, inflation, and lowered demand have combined to reduce the benefits of conversion to its investors. The same company also complained that failure to receive adequate rate relief curtailed the company's ability to finance new projects, such as conversion of their oil-burning units in the near future.

Though nearly all utilities are experiencing difficulties in raising capital, small utilities stated that this was especially difficult for them. One utility cited a cost of $200-225 million to convert a 429MW unit to coal. This estimate excluded scrubbers which would add $75 million to the cost of conversion. The amount represented over five times the original investment and exceeded the utility's recovered cost in the unit by almost tenfold. Rather than invest in the conversion, the utility would prefer to invest in a new coal-fired plant as a jointly-owned unit with neighboring utilities (New England G&E). The investment toward a new unit was preferable over raising capital to convert an oil-fired unit that is already about halfway through its life. However, the DOE has recently issued a proposed order to proceed with the plant conversion (Canal). DOE calculations have concluded that conversion to coal is more economical than continuing to burn oil or to build a new coal-fired generating station. Using an oil cost of $30/bbl and a

coal cost of $48/ton (1990 cost in 1980 dollars), and assuming a 65 percent capacity factor, the cost of electricity would be cheaper with a new coal-fired plant. In addition, DOE calculated that the cost of electricity would be much less with coal conversion than continuing to burn oil. The continued use of oil rather than converting to coal could be from 10 to 54 percent more expensive.

One municipal utility did convert its plant from oil to coal. This city, with a population of less than 10,000, spent $540,000 for its boiler conversion. Once operating, however, it was in violation of state emission standards (1979) and had to shut down. The city now has to purchase most of its power. The sequence of events for this municipal utility illustrates an apprehension which has been cited by other small utilities. The original boiler could burn natural gas or No. 2 oil. The gas deliveries were stopped and the plant was put on oil. The rising cost and supply uncertainties for No. 2 prompted the conversion to coal. Now, with the coal plant unable to operate, the city's generation capability was dropped by 60 percent. Only two small diesel units currently generate and the city purchases the remaining power needed to meet its demand.

There is some concern over the meaning of the FUA relative to gas-fired utilities somehow converting to coal. The most practical way to achieve this would be retire gas-fired plants. However, retiring useful generation earlier than planned results in an unusual impact on ratepayers and stockholders (West Texas). The utility has covered a transition to alternate fuels in its long-range planning, but is reluctant to plan for phasing out reliable gas-fired capacity prior to a planned retirement. In Texas, a large portion of the gas-fired generating units were built after 1970. An analysis performed for a state agency in Texas concluded that changing gas-fired generation to coal would cost Texas utilities $32 billion by 1995; an increase of 107 percent ($15.6 billion to $32.3 billion) over expenditures currently planned. Table 3-2 below describes capital expenditures for the Electric Reliability Council of Texas under three alternative FUA scenarios. 4/

Although many of the affected utilities could meet their FUA obligations by simply switching to oil- or gas-fired steam turbine units which are capable of continuous oil firing, most utilities have rejected that option for a number of reasons: (1) the availability and price of natural gas; (2) the diseconomies of using oil because its Btu-equivalent cost is significantly higher than gas; and (3) the long-term uncertainty of oil supply and price.

3.1.2.2 Site Limitations and Environmental Restrictions

Environmental Restrictions: Some small utilities indicated that environmental regulations, particularly Federal air quality laws, create impediments to conversion of existing plants to coal, to development of new coal-fired generating plants, and to experimentation with innovative technologies

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4/ Report of the Advisory Committee on Industrial and Electric Utility Fuel Use Policy. Texas Energy and Natural Resources Council. June 11, 1980.

TABLE 3-2
REQUIRED CAPITAL EXPENDITURES UNDER ALTERNATIVE SCENARIOS, 1986-2000. (BILLIONS OF 1980 DOLLARS)

Electric Reliability Council of Texas (ERCOT)

	Base Case (1)	Fuel Use Act Case (2)	Delay Case (3)
1986-2000	7.9	8.0	7.7
1991-1995	15.6	32.3	14.0
1996-2000	20.8	20.8	20.3

Source: Report of the Advisory Committee on Industrial and Electric Utility Fuel Use Policy. Texas Energy and Natural Resources Council. June 11, 1980.

Notes: (1) The base case assumes that the FUA is not in effect.

(2) The FUA case assumes an implementation of the Act.

(3) The delay case assumes no implementation of the Act and construction of nuclear and coal units delayed by one year.

(Lakeland, Central Telephone, Farmington, Central Hudson, Detroit, West Texas, South Mississippi, Houma, Minnesota Power, Iowa-Illinois, Columbia). In order to construct a coal-fired unit, the following types of Federal and state permits may be required: water quality, water use (including dredging and filling operations, dam and levee construction, and beneficial use of water), solid waste disposal, floodplain development approvals, and air quality. The impediments identified included the substantive requirements of the various permit programs, the length and complexity of the permitting processes, particularly if an Environmental Impact Statement is required; and the inflexibility of EPA's standards as applied to mandatory conversions.

Federal air quality laws under the Clean Air Act Amendments of 1977 (particularly as applied to the burning of low-sulfur coal) were mentioned by several utilities as significant constraints to conversion to coal. Under the NSPS for sulfur dioxide emissions, solid fuels with low-sulfur content (producing stack gases of less than 0.6 lb SO_2/million Btu heat input) are required to be "scrubbed" to a 70 percent removal standard. Although the 70 percent removal standard is less stringent than the 85 percent standard originally proposed, implementation of the standard requires the use of scrubbing technologies which are not presently in wide use.

Many of the small utilities most impacted by the prohibitions of the FUA are located within reasonable proximity to sources of low-sulfur western coal, but may realize no cost advantage by its use because of the NSPS. They perceive this to be a significant constraint to coal conversion.

In PSD non-attainment areas, EPA's stringent standards are viewed as significant impediments to coal conversion (Burbank). Two other utilities framed the argument in geographic items: coal conversion in the Northeast will require retrofitting of flue gas desulfurization equipment to existing units. However, EPA is not requiring the retrofitting of such equipment on existing powerplants in the Midwest which emit SO_2 that may believe are the cause of "acid rain" in the Northeast (Central Hudson, New England Gas).

Site Limitations: The site limitations mentioned by small utility managers were in most cases peculiar to individual utilities. There was no indication whether these limitations would be used to support a site limitation exemption petition (Title III, Section 311(a)).

Municipal utilities are particularly sensitive to site limitation issues. In most cases, there is insufficient acreage to construct a coal-fired unit at any existing site (Dover, Lamar, Burbank, Houma, Columbia, Key West, Detroit, Lincoln, Public Service of New Hampshire). In many cases, building has occurred around the original plant site. Under such circumstances, a city cannot convert its plant from oil or gas to coal due to lack of space for coal storage, ash handling equipment, and sometimes also due to lack of roadway or rail access for fuel shipments. Some municipal utilities converted from oil in the early 1970's for environmental reasons and have replaced their coal storage area with oil tanks and associated equipment (Dover). In one case, the stack height requirements for a coal-fired unit would violage height restrictions required for the glide path to a major airport (Tucson).

Water availability was cited as severe restriction in attempting to substitute coal-fired for gas-fired units; particularly in the arid Southwest region (West Texas). The company exprssed concern that there was not enough water available in their service area to satisfy cooling water needs for the number of coal units necessary to replace their existing gas-fired system (see Appendix A).

The site limitations discussed above appear to fall within the scope of the site limitation definition in Section 103(a)(16) of the Act. 5/ There is no conclusive information regarding how many small utilities are confronted with site limitations.

3.1.2.3 Availability and Low Base Period Use of Natural Gas

The present availability and price of natural gas are a major disincentive for small utilities subject to the FUA. Most gas burning utilities had not experienced difficulties negotiating favorable long-term gas contracts, although some contracts were for interruptible supplies. Nor did they anticipate difficulties in renewing or extending the contracts when they expired. In general, the utilities seemed optimistic about gas supplies through the 1980's and 1990's. Although none expressed a desire to plan and construct a new gas-fired unit, the prevailing attitude favored the continued use of natural gas in existing units when available and the use of fuel oil during natural gas curtailments until the units are retired. This uncertain course was still perceived as more economically rational than conversion or replacement of existing gas-fired units with units using alternate fuels.

Paradoxically, a large number of utilities cited non-use of gas during 1977 or low base period (1974-1976) usage of natural gas as a significant impediment to compliance with the FUA during the 1980's. Low base period usage lessens the

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5/ FUA Section 103(a)(16) the term "site limitation" means, when used with respect to any powerplant or installation, any specific physical limitation associated with a particular site which relates to the use of coal or other alternate fuels as a primary energy source for such powerplant or installation, such as

(a) inaccessibility to coal or other alternate fuels;

(b) lack of transportation facilities for coal or other alternate fuels;

(c) lack of adequate land or facilities for the handling, use, and storage of coal or other alternate fuels;

(d) lack of adequate land or facilities for the control or disposal of wastes from such powerplant or installation, including lack of pollution control equipment or devices necessary to assure compliance with applicable environmental requirements; and

(e) lack of an adequate and reliable supply of water, including water for use in compliance with applicable environmental requirements.

attractiveness of the system compliance option, because system usage between 1990 and 1995 is tied to 20 percent of base period usage. During the mid-1970's, curtailment of natural gas for boilers to interruptible customers was prevalent among interstate gas suppliers (Clarksdale, Empire District, Pratt). Purchase and transmission agreements in Florida during the heavy curtailment period in 1974-76 reduced natural gas availability to some municipal systems (Orlando, Tallahassee, Gainesville), consequently affecting their base period use of gas for the FUA compliance purposes.

Small utilities in Florida are concerned that Section 301(a) and 501 will most heavily impact municipal systems and that large utilities will have a competitive advantage. While the municipals were curtailed during 1974-76, the large utilities (IOU's) in the state were not curtailed. In addition, if the gas supplier has available supplies for the municipals, but the municipals cannot use gas because of the FUA restrictions, the large utilities would buy the gas under new interruptible contracts in the 1980's. This situation is currently under investigation by the Federal Energy Regulatory Commission. For the municipals, the exemption process appears to be the only available escape from this problem.

In one case, a small utility purchased its base load power during the the base period, thereby reducing the amount of gas that it would have normally used for generation has substantially increased over the amount of power purchased. The utility expressed concern about its gas consumption allowed under the FUA being based on the years when its use was abnormally low. 5/

A number of small gas-fired systems are located in close proximity to natural gas sources. Several of these have invested in their own gathering systems and pipelines to local fields, the yield of which, in some cases, is under contract for the life of the field (Lamar, Sunflower, West Texas, Lafayette). Others have direct access to nearby gas fields with contracted supplies (Western Farmers, Central Telephone, Farmington, Garland, Denton, Bryan, Greenville, Brazos). These utilities have been in good positions to maintain secure gas supplies and are seriously affected by natural gas use prohibitions.

At the present time, the availability of natural gas as a boiler fuel is sufficient for small gas-fired utilities to continue to use gas as their primary fuel. Responses from many small utilities have indicated that, based on availability and cost, continued use of gas is strongly preferable to near-term conversion to oil (Marshfield, Dover, Brazos, Pratt, Lincoln, Gainesville, El Paso, Colorado Springs, Empire District, Glendale, Missouri Utilities, Columbia). Examples of current prices for the fuels illustrate why there is intense interest in avoiding switching from gas to oil. One municipal quotes $2.95/million Btu for natural gas as opposed to $6.50/million Btu for No. 2 fuel oil (Marshfield). Another mentioned that the increased cost for oil to displace natural gas will be 500 percent over current fuel expenditures (Pratt). Another municipal utility quoted fuel cost of 3.5c/kwh for their existing unit. If the unit uses oil, the cost increases to 8.5c/kwh (Columbia). The ready availability and competitive price of natural gas provide little or no incentive to switch to alternate fuels.

5/ Note, however, that Title III sets a limit on the proportion of gas that can be used in a specific unit. Thus, a unit that operated at a low capacity factor during the base period, but always burded gas, could operate during the 1980's on gas at a higher capacity factor.

3.1.3 Compliance Constraints-New Capacity

There have been no indications that small utilities have yet experienced compliance problems regarding the use of oil or gas in new powerplants (Title II of the FUA). It was evident that no small system had planned new gas- or oil-fired generation for several years except for a small number of combustion turbines for peaking (Owatanna, Merced, Southern Indiana). Title II also requires that all new powerplants must have "the capability to use coal or any other alternate energy source." 6/ As described above, the thrust of small utilities concerns has been toward Title III. However, some aspects of the problems in dealing with Title III may also significantly impede small utilities from complying with Section 201(2) and related sections in Title II.

3.1.3.1 New Coal-Fired Units

Discussions with representatives from small utility operations and trade associations representing small producers have emphasized their dependence on coal-fired generation as a means for continuing a reasonable cost energy supply.

Several small utilities appear to have had little difficulty with financing small coal-fired units, at least to the extent that increased costs have not caused them to cancel a unit. Table 3-3 summarizes information obtained by DOE staff from small utilities that had planned, or were still planning construction of small coal-fired units. Significantly, some utilities cancelled plans for their small units in favor of purchasing joint ownership in larger plants being constructed by other utilities. Still, there are a number of small coal-fired units being constructed. Two major points emerge from this information: (1) despite the unfavorable economies of scale, some utilities are building small plants, and (2) many of these units were begun prior to the passage of the FUA. Therefore, it is evident that utilities have been aware of the necessity of moving to alternate fuels before the passage of the FUA. This seems to be one of the main arguments raised concerning implementation of the Act. Several utilities, large and small, have already planned for base load coal-fired or nuclear generation, but argue that the time frame for compliance with the FUA does not provide enough time to complete plans and/or to construct new facilities (Burbank, Lea County, Lubbock, El Paso, West Texas).

The time for completion of a large coal or nuclear plant, from planning to operation, has lengthened over the past ten years; averaging eight years for a 600 + MW coal-fired plant; and up to 12 years for a nuclear generating unit. Reasons for the longer periods include difficulties in raising capital, siting and licensing procedures, changes in a utility's demand forecast, and failure to meet equipment and labor schedules during construction. Information from some small utilities that have small coal-fired plants in various stages of development has shown that these same problems have also been encountered Table 3-3).

7/ Section 201(2).

TABLE 3-3
SMALL UTILITY COAL-FIRED UNITS

ERA REGION	UTILITY	NET CAPACITY	FUEL	ESTIMATED COST	COMMENTS
11	Montana-Dakota Utilities	120MW	Lignite	NA	Cancelled in favor of joint venture with Basin Electric's two 500MW units.
15	Sierra-Pacific Power Co.	125MW	Bit.	NA	Cancelled in favor of joint venture with Utah Power and Light to construct large coal-fired plant: 125MW share.
6	Grand Haven, Michigan	60MW	Coal	$1,200/kw	On schedule for 1983; some environmental problems have raised cost.
1	Arizona Electric Power Coop.	175MW	Sub.	$680/kw	On-line 1979; no licensing problems.
12	Muscatine, Iowa	150MW	Coal	$1,100-1,250/kw	Currently seven months slippage; cite EPA permits as causing delay and higher cost.
2	Black Hills Power and Light Co.	100MW	Sub.	$1,600/kw	Deferred until 1985 in favor of joint venture with Pacific Power and Light 322MW WYODAK plant.

TABLE 3-3 (Continued)

ERA REGION	UTILITY	NET CAPACITY	FUEL	ESTIMATED COST	COMMENTS
7	Grand Island, Nebraska	100MW	Bit.	$900/kw	Environmental requirements and delayed completion date; dropped joint agreement due to environmental problems.
8	Hastings, Nebraska	70MW	Sub.	$1,000/kw	No environmental problems; on-line in 1982.
10	Marquette, Michigan	47MW	Coal	$950/ 1,000/kw	Scheduled for operation in 1982; need additional capital to finance environmental controls.
19	Western Farmers Coop	376MW	Coal	$1,000/kw	Scheduled for operation in 1982; on schedule.
17	Sunflower Electric Coop	319MW	Coal	$1,350/kw	Scheduled for operation in 1983.
9	Lakeland, Florida	334MW	Coal	$600/kw	Joint venture with Orlando, includes RDF option; on schedule for operation.
13	Plains Electric G&T	210MW	Coal	$1,350-1,400/kw	On schedule for 1984 operation.
5	Gainnesville-Alachua County, Florida	235MW	Coal	NA	Delayed six months to June 1981 operating date; no licensing problems; this size unit most economical for system.
14	Savannah Electric Power Co.	175MW	Coal	NA	Currently in planning stage for 1987-88 operation.
16	Southern Indiana Gas and Electric	250MW	Coal	$740/kw	Scheduled on-line in 1984-85; purchase power more economical in the interim.

TABLE 3-3 (Continued)

ERA REGION	UTILITY	NET CAPACITY	FUEL	ESTIMATED COST	COMMENTS
4	Empire District Electric Co.	90MW	Coal	NA	Cancelled in favor of joint venture with Kansas Power and Light 650MW plant.
18	Upper Peninsula Power	80MW	Bit.	?	Plant being built by industrial firm for UPP purchase; needs power due to geographical isolation; some schedule delay.
3	Colorado Springs	200MW	Coal	$750/kw	In-service April 1980; pollution abatement costs estimated at 30-35 percent of total cost.

Many small utilities will realize on-line base load generation well before 1990 (Western Farmers, Sunflower, Plaines G&T, Dover, Cajun Electric, Lakeland, Iowa-Illinois, Savannah Electric). Others have purchased portions of large coal-fired plants which will be on-line prior to the 1990 cutoff of natural gas (Central Telephone, Fulton, South Texas, Washington Water Power, Tucson Electric, Arkansas Electric Cooperative, Austin, Anaheim, Tri-State). This action by small utilities is a result of foresight on the part of these utilities regarding the move to coal from oil- and gas-fired generation (see also Chapter 5).

Three small utilities believe their options with respect to alternative technologies are limited by diseconomies of scale associated with units smaller than 100MW (Farmington, Lamar, Lea County). They believe technologies appropriate for small scale power generation are essentially natural gas or petroleum based.

The Lamar feasibility study mentioned above analyzed three alternatives:

- Addition of a new 20MW coal-fired unit (new boiler and turbine) without scrubber at a cost of $25.9 million (1981 dollars) or $0.06417 per kwh;
- Addition of a new 20MW coal-fired unit (new boiler and turbine with scrubber at a cost of $27.3 million (1981 dollars) or $0.07121 per kwh; and
- Addition of a new 45MW coal-fired unit (new boiler and turbine used in conjunction with existing turbine) with scrubber at a cost of $39.1 million (1981 dollars) or $0.05609 per kwh.

The Lamar Utilities Board rejected all three alternatives as being too expensive, particularly when compared with the cost of a syngas plant and joint-ownership options being studied concurrently (see Appendix A).

Although few other utilities contacted had actually undertaken feasibility studies for small coal units, some seemed to accept the diseconomies of scale associated with such units as a fact. Independent engineering studies prepared by consultants for the public power associations are probably the sources of this conviction. Table 3-4, prepared by R. W. Beck and Associates for the Indiana Municipal Electric Association in 1979, compares the annual fixed and variable costs for municipal utilities of various sized coal-fired steam turbines and oil-fired combined-cycle turbines.

TABLE 3-4
COMPARISON OF ANNUAL FIXED AND VARIABLE COST
AT COST OF CAPITAL FOR MUNICIPAL UTILITIES ($1978) 1/

UNIT SIZE	PRIME MOVER	FUEL	CONSTRUCTION COST $/kw (1979)	ANNUAL FIXED COST $/kw/yr	VARIABLE COST MILLS/kwh	TOTAL COST 2/ MILLS/kwh
50MW	Steam	Coal	965	171.7	14.80	44.9
100MW	Steam	Coal	737	124.0	14.02	35.7
150MW	Steam	Coal	696	113.1	13.62	33.5
250MW	Steam	Coal	626	99.7	13.33	30.7
300MW	Steam	Coal	608	95.7	13.10	29.9
400MW	Steam	Coal	566	88.3	13.07	28.6
500MW	Steam	Coal	544	85.0	12.98	27.9
650MW	Steam	Coal	525	81.4	12.84	26.1
25MW	Comb. Turbine	Oil	270	34.0	61.10	67.1
60MW	Comb. Turbine	Oil	184	23.0	61.10	65.1
65MW	Comb. Turbine	Oil	225	28.0	54.05	59.0

1/ Preliminary Power Supply Study for the Indiana Municipal Electric Association Joint Action Committee. R. W. Beck and Associates, 1979.

2/ Estimates added by DOE, based on a 65 percent capacity factor.

Small utilities are constructing coal-fired units ranging in size from 47MW to 376MW (see Table 3-3). One of these small systems is constructing a 60MW unit scheduled for operation in 1983 (Grand Haven). Preliminary studies for this project were begun in the early 1970's and specific technical studies were completed in 1979. The unit is on scheduled at an anticipated cost of $1,200/kw (1980 dollars). The original cost estimate for the project has increased 800 percent over ten years. Nevertheless, the project cost is in the range with other facilities listed in the table.

Hastings, Nebraska, is constructing a 70MW subbituminous coal-fired unit with an anticipated operation date in 1982. The municipal began planning for the unit in 1977 and has an anticipated cost of $1,000/kw (1981 dollars). The citizens of Hastings elected to construct this unit even though studies indicated that other options (purchase power, enter into a joint venture or purchase a share of a 600MW coal-fired unit owned by Nebraska Public Power District) would be less costly. The decision may have been the result of an earlier joint project that had to be abandoned because of environmental problems and delays.

Though there are small utilities investing in small coal-fired unit, there are also several small systems that have cancelled or deferred small coal-fired units in favor of joint participation in larger plants being constructed by larger utilities (Sierra Pacific, Montana-Dakota Utilities, Black Hills, Empire District, Upper Peninsula). The economies-of-scale issue, therefore, appears to be unresolved and dependent on a system's particular circumstances and management policy.

3.1.3.2 Nuclear Units

Many small utility systems have purchased shares of nuclear plants for base load, using their small boilers for peaking or intermediate. Many small municipal and cooperative systems already own shares in operating reactors. 7/ Table 3-5 lists small utilities between 10-2,000MW that are participating in operating nuclear plants.

Small utilities have not had the financial or technical capability for sole-owning and operating nuclear plants, particularly with the evolution of increased sizes of nuclear units since 1965. To make up for this lack of resources, small systems have aggressively pursued part ownership of plants planned by large bulk power suppliers; usually investor-owned utilities. Many small utilities' representatives were enthusiastic about participating in nuclear plants, although there was considerable concern about the uncertainties associated with U. S. nuclear policy in the aftermath of Three Mile Island.

There were several instances where small utilities' future generation plans emphasized shares of proposed nuclear plants. In these cases, each small utility was constructing a coal-fired plant as well as purchasing portions of nuclear units scheduled for on-line before 1990. They were confident that the nuclear shares, in addition to completion of their coal-fired plants, will eliminate their concern about the FUA off-gas provisions set for 1990 (Western Farmers, Brazos, Washington Water Power, Sunflower).

7/ Owners of Nuclear Powerplants, Office of Nuclear Reactor Regulation, U. S. Nuclear Regulatory Commission, NUREG-0327.

TABLE 3-5
SMALL UTILITY PARTICIPATION IN NUCLEAR POWERPLANTS*

ERA REGION	SYSTEM	PLANT	CAPACITY (MW)	MW SHARE
27	Anaheim, California	San Onofre #2** & 3	2,000	36.52
21	Associated Electric Coop.	Black Fox #1 & 2	2,300	500.0
5	Atlantic City	Salem #1**	1,170	86.7
		Peach Bottom #1 & 2**	2,304	175.0
23	Austin, Texas	South Texas #1 & 2	2,500	400.0
19	Brazos Electric Coop.	Camanche Peak #1 & 2	2,300	87.4
3	Burlington, Vermont	Pilgrim #2**	1,180	3.89
		Millstone #3	1,156	4.22
7	Bushnell, Florida	Crystal River #3**	825	.32
3	Cambridge Electric Light	Maine Yankee**	864	34.5
		Vermont Yankee**	563	14.0
		Yankee Rowe**	185	3.7
4	Central Hudson Gas and Electric	Sterling	1,192	202.6
		9 Mile Point #2	1,166	105.0
20	Central Iowa Power Coop.	Duane Arnold**	597	119.4
3	Chicopee, Massachusetts	Millstone #3	1,156	15.61
20	Corn Belt Power Coop.	Duane Arnold**	597	59.7
19	Dairyland Power Coop.	LaCrosse**	50	50.0
	Dalton, Georgia	Vogtle #1-4	4,452	71.23
		Hatch #1 and 2**	1,581	34.78
25	Eugene, Oregon	Trojan #1**	1,130	399.0
7	Gainesville, Florida	Crystal River #3**	825	11.61

TABLE 3-5 (Continued)

ERA REGION	SYSTEM	PLANT	CAPACITY (MW)	MW SHARE
3	Hudson, Massachusetts	Pilgrim #2	1,150	1.96
		Seabrook #1 & 2	2,400	.48
20	Interstate Power Company	Carroll County	2,350	430.0
20	Iowa-Illinois Gas and Electric Company	Carroll County #1 & 2	2,350	352.5
21	Kansas Electric Power Coop.	Wolf Creek	1,150	195.5
7	Kissimee, Florida	Crystal River #3**	825	5.57
7	Leesburg, Florida	Crystal River #3	825	6.80
20	Lincoln, Nebraska	Cooper**	800	100.0
	Lyndonville, Vermont	Millstone #3	1,150	.58
3	Massachusetts Mun. Whole - Sale Electric Company	Pilgrim #2	1,180	156.2
		Seabrook #1 & 2	2,300	128.8
		New England #1 & 2	2,300	138.2
		Millstone #3	1,150	55.0
		Montague #1 & 2	2,300	33.3
9	Mun. Electric Authority of Georgia	Vogtle #1-4	2,226	394.0
20	Nebraska Public Power District	Hatch #1 & 2	1,581	279.84
		Cooper**	800	700.0
7	New Smyrna Beach, Florida	Crystal River #3**	825	4.63
12	North Carolina Mun. Power Agency	Catawba #2	1,153	864.75
18	Northern Michigan Electric Coop.	Fermit #2	1,123	126.0
7	Ocala, Florida	Crystal River #3**	825	11.0
9	Oglethorpe Power Corp.	Vogtle #1 & 2	2,200	660.0
		Hatch #1 & 2	1,561	468.3
20	Omaha Public Power District	Fort Calhoun**	457	457.0
4	Orange and Rockland Utilities	Sterling	1,150	378.5

TABLE 3-5 (Continued)

ERA REGION	SYSTEM	PLANT	CAPACITY (MW)	MW SHARE
7	Orlando, Florida	Crystal River #3**	825	13.21
27	Riverside, California	San Onofre #2 & 3**	2,200	39.38
28	Sacramento Mun. Utility District	Rancho Seco #1**	913	913.0
7	Sebring, Florida	Crystal River #3**	825	3.69
12	South Carolina Public Service Authority	Summer	900	300.0
21	Sunflower Electric Coop.	Wolf Creek	1,150	34.5
7	Tallahassee, Florida	Crystal River #3**	825	11.0
3	Taunton, Massachusetts	New England #1 & 2	2,300	11.5
		Pilgrim #2	1,180	7.08
		Seabrook #1 & 2	2,400	2.40
23	Texas Municipal Power Agency	Comanche Peak #1 & 2	2,300	142.6
3	Vermont Electric Coop.	Millstone #3	1,159	11.6
		Pilgrim #2	655	131.0
		Seabrook #1 & 2	2,386	98.4
25	Washington Water Power Company	Skagit #1 & 2	2,690	269.0
		WPPSS #3	1,242	62.0
22	Western Farmers Coop.	Black Fox	2,300	400.0
17	Western Illinois Power Coop.	Clinton	950	90.25
18	Wolverine Electric Coop.	Fermi #2	1,123	98.5

* Information partially supplied by APPA and NRECA.

** Operating reactors.

3.1.3.3 Purchased Power

Some small utilities with their own base load generation view purchased power as only an interim measure for base load requirements until an equity interest in new capacity can be obtained through construction of joint ownership of a plant (Lamar, Farmington, Central Telephone). Other small utilities are only peaking utilities which rely exclusively on purchases of base load power from other utilities (McPherson, Ottawa, Iowa Power).

Lack of control over the direction, cost, and availability of future bulk power are usually cited as the reasons for rejecting purchased power as the principal base load source. Beyond these economic rationales, however, publicly owned base load generating utilities expressed reluctance to become "entangled with" or "dependent upon" other utilities, particularly investor-owned utilities, for philosophical or political reasons. There seems to be an inverse relationship between the strength of the utility's commitment to "public power" and the amount of power which the utility is willing to purchase from an IOU (Farmington, Lamar, Lubbock).

3.1.3.4 Lack of Available Capital

There were small utilities, municipally and investor-owned, which asserted that they would be unable to comply with the FUA because of lack of available capital (Lubbock, Orlando, Central Hudson, Central Telephone, Sierra Pacific). The municipally-owned utilities frame their argument as follows: in order to achieve the base load shift to alternative technologies (such as coal) required by the Act, the city would have to receive bonding authority from the voters to construct a new plant to replace existing capacity, a prospect which the voters are likely to reject (Lubbock). Some municipal utilities have stated that the bond issue required to construct a new alternate fuel fired powerplant would be many times larger than any bond issue the voters had ever considered, and that there would be virtually no chance of passage (Vero Beach).

In Lubbock's case, this argument is acute due to the no-growth or low-growth status caused by direct, street-by-street competition with an IOU. In other words, it is unlikely that a new unit could be economically justified to the voters under the circumstances, given the existing investment in gas-fired capacity, even though the voters enjoy the fruits of this competition: i.e., lower rates and better service.

Potentially, many municipal utilities could make this argument against compliance with the FUA in this day when city councils must vigorously advertise in order to pass bond issues.

The IOU's were concerned both with their expected inability to attract capital in this troubled economic period and with justifying the new capacity required by the FUA to the public utility commissions to obtain necessary rate increases (Central Telephone, Empire District, Central Hudson).

3.1.3.5 Availability of Alternate Fuels

Some utilities cited problems with obtaining coal from developed sources, particularly uncertainties associated with increasing railroad transportation costs (Lamar) and lack of rail service (Lea County, Houma, Lafayette, South Mississippi, Wallingford, Burbank). Other utilities were located in close proximity to existing or proposed mining sites and did not foresee insurmountable problems with obtaining coal or lignite (Garland, Denton, Greenville, Bryan, Farmington).

Only one utility interviewed stated that it was considering purchasing its own lease in order to obtain a source for a future plant or to use as a "bargaining chip" in a joint action project (Farmington, see Appendix A). Several other small utilities were developing lignite sites through the joint agency or purchase share mechanisms (Garland, Denton, Bryan, Greenville, Brazos, South Texas, Medina). Chapter 5 presents a further evaluation of these trends.

A number of small utilities believe that alternate fuels, such as biomass, solar, geothermal, wind, and syngas derived from coal or lignite, are practically "unavailable" because the high cost and/or experimental nature of the necessary technologies render them infeasible for a small system without government funding. They suggest that these sources are unlikely to be commercially available by 1990 (Lubbock, EUA Service, Burbank, APPA).

Chapter 4
Compliance Strategies

4.1 Existing Units

Although gas-dependent utility systems are heavily impacted by the statutory prohibitions in Section 301, few gas-fired utilities contacted in this study seem to have made final decisions on a compliance strategy. The options they are considering include conversion to oil, conversion to coal, synthetic fuels or other alternate fuels, system compliance under Section 501, temporary or permanent exemptions, and sale or retirement of the facilities.

4.1.1 Fuels Conversion

Some small utilities have indicated that they have made economic decisions rejecting conversion to coal or oil as a viable option for bringing their existing units into compliance with the prohibitions of the Fuel Use Act (FUA); citing questionable sources for capital and restricted time frames (see Section 3.1.2.1).

One utility, however, indicated that it had voluntarily converted two of its larger units from gas to coal firing in 1977, apparently on the basis of economics (Empire District). One utility had converted a 7.9MW gas-fired unit to coal in 1979 at a reported cost of $540,000 (Trinidad). Another utility expressed a desire to convert back to coal two oil-fired units (120 and 220MW, respectively) but indicated that the company probably could not finance the project, estimated to cost $140 million with flue gas desulfurization equipment, without government assistance (Central Hudson).

Conversion of oil-fired units to coal-oil mixtures is also being seriously considered by a few small systems (Lakeland, South Mississippi). Lakeland has applied for a DOE grant to develop a coal-oil mixture (COM) technology for their existing units. However, the city has expressed concern over air quality regulations as a hindrance to testing new technologies. There is no provision for emission variances for new technologies like COM. Should Lakeland have the opportunity to develop COM, there will be a period of development during which it will need to continue burning natural gas. South Mississippi attempted to participate in a test program for COM with its units using No. 6 fuel oil. The utility was declared ineligible by DOE because the units were originally designed for natural gas. One utility is already using COM in four units that were originally designed for coal (Minnesota Power and Light).

Several other small utilities were seriously investigating various types of synfuels to replace all or a portion of their gas requirements without requiring substantial modifications of their existing units.

In 1977, prior to the passage of the FUA, Lamar Utilities hired a consulting firm to do a feasibility study for a biogas conversion facility using cattle manure from nearby feedlots as the raw material. The feasibility study for the biogas plant was done concurrently with a feasibility study on conversion of an existing unit to coal and the addition of coal-fired units. The biogas plant, designed to supply one million cubic feet per day at 1,000 Btu's per cubic foot of gas, was determined to be a highly feasible option compared to the other alternatives being studied. At a cost of $14 million, the plant is anticipated to supply one-third of the system's total demand for gas and to replace an existing natural gas

contract for an interruptible supply. Based on a 20 year plant life and 300 operating days per year, the equivalent gas cost is estimated at $2.33/MMBtu. Lamar Utilities anticipates letting the contract for the biogas plant in October 1980, and expects the plant to be fully on-line within 24 months. Chapter 6 of this report treats the biogas potential in more detail.

The City of Farmington is also studying a synfuel supply, though Farmington's plans are much more speculative. A medium-Btu coal gasifier, which has been in planning for ten years, is proposed to be built within 35 miles of the city at an estimated cost of $3 billion by Texas Eastern Synfuels Corporation and Utah International. Although the plant presently has a 1983-84 startup date, the city is taking a wait-and-see attitude before negotiating for a supply of synthetic fuel. If the plant is constructed as planned and the cost of the synthetic gas is reasonable, the city has tentative plans to negotiate for biogas in order to extend the lives of its existing units past 1990. However, future negotiations will be contingent on the price of the fuel, which at this time is not known.

Other small systems studying the synfuel conversion option included Glendale, Iowa-Illinois Gas and Electric Company, and Lea County Electric Cooperative. Iowa-Illinois is a participant in the North Dakota Synthetic Fuels Feasibility Study which is examining the possibility for producing synthetic fuel from lignite.

4.1.2 System Compliance Option

Some small utilities are considering the system compliance option. As an alternative to seeking exemptions for individual units, a utility may, under Title V, negotiate a system compliance plan with the ERA.

A system compliance plan, under Title V of the FUA, must contain the following binding commitments:

- That on or after January 1, 1980, the utility will not use natural gas in its system in excess of 20 percent of the base period usage or, if lower, the minimum peak load requirement for the calendar year;
- That from 1995 to 2000 the utility will not use natural gas as a primary energy source, except for peak load or intermediate load; and
- That on or after January 1, 2000, the utility will be completely off the use of natural gas in its supply.

A system compliance plan has some advantages for a system which has or will have base load units using alternate fuels by 1990. Between 1990 and 1995 a utility with an approved system compliance plan can use its system-wide gas allotment in base load units within its system which the utility is not ready to use for peak load, or to retire. After January 1, 2000, a system compliance plan forces retirement of all gas-fired units or conversion to alternate fuels. After a plan is approved, the utility is foreclosed from seeking exemptions for existing plants (except for emergencies) and for new base load plants. The utility may be bound by the plan even if Congress later amends or repeals the FUA.

To be eligible for the option, a utility was required to file a letter of intent by January 1, 1980. The submittal of a system compliance plan for ERA approval had to be by August 1, 1980. Five of the ten case studies (Farmington, Vero Beach, Western Farmers, Sierra Pacific, Central Telephone) filed declarations of intent on January 1, 1980. Thirty-eight small utilities had filed similar letters of intent. On August 1, 1980, 30 small utilities submitted system compliance plans for negotiation and ERA approval. 1/

Presently, most small utilities which have filed system compliance plans are having studies made by consultants to determine whether the system compliance option will be advantageous for their systems. In the system compliance option meetings held with applicants at various cities in the United States, ERA representatives made it clear that a utility may negotiate a system compliance plan which may be abandoned at any time up until ERA notifies the utility that it intends to approve the plan.

A system compliance plan is more appropriate to the situations of some utilities than for others. Western Farmers Electric Cooperative, for example, evaluated three scenarios and developed information comparing the cost of an orderly transition from gas to other fuels between 1980-2004 to various system compliance plans. The utility's analysis stated that, while a plan would offer possibly unrestricted use of gas in existing units before 1990, the system compliance option would be "highly restrictive" for their present system after 1990. The three scenarios described in Table 4-1 outline system compliance plans under various gas allotment conditions and contingent upon peaking and/or emergency exemptions. Findings from Western Farmers' analysis indicated that the system compliance option would have an undesirable economic impact on the utility because of gas use restrictions in 1990 and absolute curtailment by 2000. The utility indicated that applying for various exemptions would be more expedient and less costly.

4.1.3 Temporary and/or Permanent Exemptions

Thirty percent of the small utilities responding to inquiries for information stated that they had received, or had applied for the following available exemptions:

- Temporary public interest exemption; 2/
- Temporary exemption for future use of synfuels;
- Temporary exemption for retirement of the unit within five years;
- Permanent exemption for fuel mixtures containing natural gas or petroleum;
- Permanent exemption for cogeneration;

1/ See footnote 3, Chapter 3.

2/ See footnote 2, Chapter 3.

TABLE 4-1
COMPARISON OF ORDERLY TRANSITION FROM NATURAL GAS WITH THREE SYSTEM COMPLIANCE PLANS PREPARED FOR WESTERN FARMERS ELECTRIC COOPERATIVE, INC. (1980) *

PLAN	GAS REQUIRED (MCF)	TOTAL INCREMENTAL EXPENDITURES REQUIRED X $1,000	GAS SAVED OVER MOST ECONOMIC PLAN (MCF)	ADDITIONAL COST OVER MOST ECONOMICAL PLAN X $1,000	COST PER MCF OF GAS SAVED
Gas Used Most Economically	300,759,656	$17,196,771	---	---	---
System Compliance Plan #1	200,959,412	19,214,810	99,800,240	2,018,039	$20.22
System Compliance Plan #2	183,144,312	19,481,312	117,615,344	2,284,751	19.43
System Compliance Plan #3	158,668,614	19,964,185	142,091,042	2,767,414	19.48

System Compliance Plan #1 - Western Farmers follows system compliance plan and is granted maximum use of gas. All gas use ceases on January 1, 2000, except for three combined cycle units which are granted peaking exemptions from 2000 through 2004. Additional coal-fired units are added to replace gas units.

System Compliance Plan #2 - Same as Plan #1, except all gas use stops on January 1, 2000.

System Compliance Plan #3 - Western Farmers follows compliance plan, but only minimum use of gas is permitted after January 1, 1990. Additional coal-fired units are added to replace gas units.

* Report on the Analysis of the Powerplant and Industrial Fuel Use Act of 1978 for the Western Farmers Cooperative. Burns & McDonnell, Kansas City. April 1980.

- o Permanent exemption for site limitations;
- o Permanent exemption for intermediate load powerplant; and
- o Permanent exemption for peak load powerplant.

There have been prepetition conferences or applications filed by small utilities for exemptions for lack of alternate fuel supply (Section 312(a)(1)(A); site limitations (Section 312(a)(1)(B); fuels mixture (Section 312(d); and for peak load powerplants (Section 312(f). Many small utilities (105) have already obtained temporary public interest exemptions to burn gas instead of oil during the early 1980's. None of the utilities contacted had actually filed applications for exemptions for new facilities. Their consultants were still studying which exemptions were most feasible and advantageous for their systems.

4.1.4 Sale or Dismantlement of System

Several small utilities were considering dismantling their systems and selling their generation and transmission facilities to larger utilities as alternatives to compliance with the FUA (APPA). Some utilities contacted in this study mentioned sale or dismantlement as a last resort. One investor-utility was considering selective closure or sale of plants unable to comply with the FUA as a compliance option.

Although the sale of a system to another utility does not by itself solve the FUA compliance problems for the system, it does shift the financial burdens of compliance to the purchasing utility. The purchasing utility may have sufficient capacity based on alternate fuels to meet the base load requirements of the combined system while using the power-plants acquired for intermediate load or peak load only.

Selling or dismantling a system as an alternative to the FUA compliance is not purely an economic decision in the context of public power. The concept of public power has a strong philosophical element which is beyond the stated financial benefits (lower fixed costs of power because capital is raised through issuance of tax-exempt revenue bonds) and stated regulatory benefits (most municipal utilities are not regulated by their state utility commissions).

While sale of a system, as a last resort, may be an option for a small utility, such a purchase may not be attractive to larger utilities. In many instances, a small power system can be comprised of old generating units approaching retirement, a weak distribution system with limited capabilities, and no substantive materials inventory that would be valuable to a larger system. In addition, a municipal system will be subject to a vote by the community which may not favor sale of its municipal property.

4.2 New Capacity

Plans to install gas-fired or oil-fired generating units to meet future demand have been stifled in recent years by large price increases for gas and oil, coupled with long-term uncertainties about the availability of these fuels. Though many small utilities commented on the desire to build new gas-fired combined cycle turbines, there were no operators that seriously considered such a move given the policy dictates of the FUA.

The strategy which small utilities are pursuing for their existing units depends in large measure upon the plans they have made for new capacity or for purchased power to satisfy their base load requirements. The compliance strategies available to small utilities for shifting their base load power to such technologies are as follows:

- o Purchased power;
- o Construction of a new base load unit using alternate fuels; and/or
- o Construction of a jointly-owned base load unit using alternate fuels or purchase of a capacity share of such a unit under construction or being planned.

Variations on the above have been found among small gas-fired utilities which have, through long-term planning, anticipated no compliance problems with the FUA. One system plans to completely switch to purchased power in 1990, keeping its gas-fired boilers for peaking (New Mexico Electric). Another has initiated a construction program to build coal-fired units which are expected to be in operation by 1990, reducing its use of natural gas for generation to three percent of total fuel use (Public Service of New Mexico). The Texas Municipal Power Agency, a joint action agency, has instituted plans for building a coal-fired generating station that will serve four municipal utilities (see Chapter 6) and displace natural gas use by 1990. Another gas-fired municipal will eliminate its gas use with a coal/lignite facility and shares of a nuclear unit and expects to be completely off-gas by 1990 (Ruston). Two other small utilities do not anticipate compliance difficulties. They have coordinated their planning to include future long-term contracts for purchased power from proposed Federal hydro projects and are joint owners of a lignite plant currently under construction (South Texas, Medina). In the event that either of these are delayed, the utilities will look for exemptions in the interim.

The examples above illustrate that small utilities have opportunities to meet the requirements of Title III of the Act. Some conditions, however, have to be met before a utility can even hope to be in compliance. There must have been long-range planning for alternate fuels begun earlier than the effective date of the FUA. A small utility has to be in an area where neighboring utilities are constructing coal or nuclear base load generation, and must be in a financial position to invest in new facilities. Not all small utilities are fortunate enough to realize these conditions. Several are in relative geographical isolation which prevents their participation in large power projects (Lea County, Upper Peninsula). Nevertheless, there are small power systems that can meet the requirements of the Act and will have few, if any, compliance problems.

4.2.1 Purchased Power

Despite the general reluctance of small base load utilities--particularly municipally-owned utilities--to purchase base load power from other utilities, several small utilities were considering purchase of a significant proportion of their base load power from another utility as a strategy to comply with the FUA by 1990 (Central Telephone, Fulton Brazos Electric, Lubbock, Lincoln, New Mexico Electric, Lea County, Lebanon). As an option, purchased-power may rank in priority above construction of a new base load unit (Lamar) or below (Farmington), depending on its cost as well as upon the municipal utility's attitude toward dependence on or purchasing from other utilities.

Most small publicly-owned utilities interviewed intended to continue purchasing some power from other utilities pending construction of or purchase of an equity interest in new units. Central Telephone and Utilities intends to use its contract with Kansas Power and Light (130MW) as a critical component of its compliance strategy. Further details

of this strategy are found in Appendix A. One utility noted that it has had difficulties purchasing power in the past, usually in an indirect-competitive situation (Clarksdale).

Several municipal utilities emphasized the anticompetitive ramifications of the FUA (Clarksdale, Gainesville, Tallahassee, Ruston, Lubbock, Pratt). The argument was articulated as follows:

- Small municipally-owned utilities sometimes compete indirectly with neighboring utilities (Coops, IOU's) which would like to serve the municipal customers;
- The larger neighboring utilities may have greater financial resources and/or more diverse fuel mixes and unit types which facilitate compliance with the FUA;
- Any additional investment resulting from the FUA compliance will substantially increase the rates of the small municipal utilities, thereby increasing the potential for dismantlement and/or sale of the municipal systems to the neighboring utilities.

The FUA may also create the need to purchase base load power from other utilities either during conversion to alternate fuels or as a permanent compliance strategy. Several small utilities view purchase of base load power as the first step toward dismantlement and/or sale of the system.

4.2.2 Jointly-Owned Base Load Unit

Small utilities appear to prefer joint ownership options. Joint ownership could involve either construction of a jointly-owned unit or purchase of capacity share of such a unit which is under construction or being planned. The small utilities which are known to be pursuing or to have pursued successfully some form of joint ownership of a unit, either independently or through a joint agency, include: Farmington, Lamar, Wolverine, Lubbock, Central Telephone, Western Farmers, Sunflower, Lea County, Plains Electric, Denton, Bryan, Greenville, Garland. (See Chapter 5 for many other utilities which are purusing joint project options.)

The types of jointly-owned units involved were usually coal or nuclear. Wolverine Electric Cooperative, in conjunction with Consumers Power Company, however, has studied the feasibility of a 25MW wood and RDF-fueled plant: the feasibility study has returned results which are encouraging the utilities to confer with local and Federal government agencies with regard to siting and funding. Other utilities have also investigated wood or RDF as a possibility, with favorable results (Lakeland, Orlando).

Table 4-2 provides detailed information about the type and status of joint ownership projects for five case-study utilities.

Several of the small utilities began investigating joint ownership prior to the passage of the FUA as a solution to the economies-of-scale problems of coal-and-nuclear-based technologies. APPA and the New York municipal bond houses have been vigorous proponents of joint action since the early 1970's, and much of the state enabling legislation authorizing joint action was passed in the middle 1970's (see Chapter 5). Approximately half of the states have such legislation in effect. The shift to

TABLE 4-2
JOINT OWNERSHIP OF UNITS BY FIVE CASE STUDY UTILITIES

UTILITY	PROJECT	PARTICIPANTS	NET GENERATING CAPACITY (MW)	UTILITY'S CAPACITY SHARE	DUE ON-LINE COMMERCIALLY	STATUS
Farmington, NM	San Juan Generating Station Unit No. 4 (coal-fired)	Public Service of NM (IOU)	450	50	1982	Near agreement
	Proposed unit (coal-fired)	Unnamed Coop	100-230	40	1985	In negotiation
Lamar, CO (as member of Arkansas River Power Authority)	Southeastern Plant Unit No. 1 and No. 2 (coal-fired)	Public Service of CO (IOU)	470 (each unit)	50-75 (ARPA)	1985-86	In negotiation
	Nixon Unit No. 2 (coal-fired)	Colorado Springs, CO (Municipal)	208	50-150	1988	Under study
Lubbock, TX	Proposed (coal-fired)	Lea County Elec. Coop, NM (Coop)	Unknown	Unknown	Unknown	Under study
Wolverine Electric Coop, MI	J.H. Campbell Unit No. 3 (coal-fired)	Consumers Power (IOU)	770	10	1980	Purchased share
	Enrico Fermi Unit No. 2	Detroit Edison (IOU) (with others)	1,215	96	1982-83	Purchased share
	Proposed (Wood and RDF-fired)	Consumers Power (IOU)	25	Unknown	1984-85	Under study
Central Telephone and Utilities (Western Power Division), KS	Jeffrey Energy Unit No. 1 and No. 2 (coal-fired)	Kansas Power and Light (IOU) Kansas Gas and Electric (IOU) Missouri Public Service (IOU)	720	57.6 (each unit)	On-line	Purchased shares
	Jeffrey Energy Center Unit No. 3 and No. 4 (coal-fired)	Kansas Power and Light (IOU) Kansas Gas and Electric (IOU) Missouri Public Service (IOU)	720 (each unit)	57.6 (each unit)	1985-87	Purchased shares

technologies using alternate fuels mandated under the FUA provided some additional impetus toward joint ownership, particularly purchase of a share of a unit already under construction or in the late planning stages (Medina, South Texas, Farmington, Lamar, Ruston).

Chapter 5.0 of this report reviews state joint action agencies and contains a detailed analysis of the legal and institutional mechanisms to joint ownership which exist in a number of states.

Chapter 5

Joint Utility Projects as a Fuel Use Act Compliance Strategy

5.1 Overview

Small utilities may comply with the Fuel Use Act (FUA) without applying for exemptions under Titles II and III, or for the system compliance option under Title V, by participating either in independent joint ownership ventures or in joint action agencies (where two or more power entities join together to form an independent political entity which supplies power to its members). Both joint action agencies and independent joint ownership arrangements permit small utilities to realize economies of scale by sharing in the output of large plants. Joint action agencies also provide the technical and financial resources needed to build and operate powerplants operating on alternate fuels.

In more recent years, a number of small utilities have entered into joint ownership arrangements for large plants. This chapter examines existing and planned joint independent ventures. It then surveys the current status of the nation's joint action agencies and reviews the problems they have overcome or are still facing in developing their ability to meet bulk power needs of their constituent small utilities. Finally, it presents results from a case study prepared on the Texas Municipal Power Agency, a joint action agency.

5.2 Independent Joint Ownership

Independent joint ownership--in which a publicly-owned utility independently negotiates with other utilities to finance, construct, and operate a jointly-owned unit--is the most common form of joint project ownership of currently operating plants.

Independent joint ownership offers the following advantages to small utilities:

- It permits a small utility to capitalize on economies of scale available in building larger generation and transmission facilities;
- It gives a small utility more options in fuel use and types of generating stations;
- It permits a small utility to spread its risks by buying shares of plants constructed over a period of years geared to load growth; and
- It minimizes siting and water use problems by decreasing the number of separate regulatory actions required and by making more efficient use of land, water, and other natural resources.

5.2.1 Joint Ownership Review

Small utilities are currently receiving power from 66 jointly-owned operating generating units; 36 percent of the total megawatt capacity of these units are owned by small utilities. Plans are underway for small

utilities to participate in 82 future units. From these units, the small utilities will receive 43 percent of the total capacity (see Appendices E and F for a list of units, owners, and respective shares). 1/

The operating units in which small utilities have chosen to participate consist primarily of coal-fired generation (36) followed by oil (10), nuclear (10), hydro (8), and lignite (2). One or more of these units are owned by 58 small utilities, 46 of which also own other generating capacity. Table 5-1 is a breakdown of the 46 generating owners by capacity and type of system.

In regard to future units, small utilities again prefer to invest in coal units (50) followed by nuclear (23), lignite (5), and oil (4). Thus far, 76 small utilities are planning to participate in future units. About 51 of these utilities own other generating facilities. A breakdown of the owners by capacity and type of system is in Table 5-2.

In pursuing joint ownership options, problems can arise for small utilities. For example:

- The lack of planning flexibility in being "straight-jacketed into participating in remote plants, governed by others, often outlandishly expensive" (Kirkwood);
- The inability to gain access to transmission facilities wheeling power from joint utility projects (Clarksdale, eight Florida Utilities, Highland, Wallingford, Imperial Irrigation District, Lubbock); and
- The refusal of neighboring utilities to allow joint participation in projects (Clarksdale, Lubbock).

Two general conclusions can be drawn from the high degree of participation in joint action projects by small utilities:

- Legal mechanisms exist in many states which allow municipalities, coops, and IOU's to jointly construct, own, and operate electric generation and transmission facilities; and
- Joint ownership is generally perceived to be a more advantageous option than either construction of a small new unit using alternate fuel or purchase of power from another utility as a means of satisfying base load power requirements and complying with the FUA.

1/ Sources for the data in this section and in Appendices E and F are:

- The 1980 Annual Reports of the nine Regional Electric Reliability Councils--East Central Area Reliability Coordination Agreement, Mid-American Interpool Network, Mid-Atlantic Area Council, Mid-Continent Area Reliability Coordination Agreement, Northeast Power Coordinating Council, Southeastern Electric Reliability Council, Southwest Power Pool, Electric Reliability Council of Texas, and Western Systems Coordinating Council.
- U. S. Department of Energy. Inventory of Powerplants in the United States. December 1979.
- U. S. Department of Energy. Additions to Generating Capacity 1979-1988 for the Contiguous United States. October 1979.

Table 5-1

Small Utilities Participating in Existing Jointly Owned Units

System Capacity MW	IOU's	Cooperatives	Municipals	Others
10-25			3	
25-50	1			
50-100		2	1	
100-200		1		
200-500	4	4	3	
500-1000	11	1	2	
1000-1500	7			1
1500-2000	3	2		

Table 5-2

Small Utilities Participating in Future Jointly Owned Units

System Capacity MW	IOU's	Cooperatives	Municipals	Others
10-50	1	1	2	1
50-100		2		
100-200		1		
200-500	5	5	2	
500-1000	9	6	1	
1000-1500	8	1		
1500-2000	2	1	1	

5.3 The Joint Action Agency

The concept of joint action agencies has existed for about three decades, but the implementation of the organizations did not blossom until the 1970's. A joint action agency is usually made up of a group of municipal and cooperative utility systems organized as an autonomous agency for purposes of supplying economy bulk power to its members. This may be accomplished by one or more of the following means: building its own generating plants, purchasing shares of existing or planned plants, and purchasing wholesale power.

The functions of the agencies vary among the groups. It can be a total or partial power requirements supplier to its members. It can negotiate and manage wholesale contracts for the individual municipalities. Operation and/or management of city-owned generating facilities can be taken over by the agency. The agency can provide services such as conducting load management studies and estimating the future needs of individual systems.

Agencies can operate only in states where appropriate enabling legislation has been enacted. Established organizations usually are political subdivisons of a state and are able to issue tax-exempt bonds to finance projects.

There are two basic types of joint agencies: those created pursuant to general law statutes authorizing municipalities and other local governmental units to create and become members of joint agencies; and those created by special statutes which authorize one statewide agency controlled by and serving customer-municipalities under power contracts. There are two sub-types of the general law joint agencies: those which authorize formation of joint agencies specifically for the supply of electric power and those which authorize formation of joint agencies to provide general municipal services and facilities, including electric power supply facilities.

Currently, 31 joint action agencies[1/] exist in 23 states.[2/] All except the two oldest, Northern California Power Agency and Washington Public Power Supply, were established in the 1970's. Only eleven of the agencies have yet entered the bond market to obtain financing for funding power projects.

Table 5-3 lists all the agencies and historical data on current bulk power supply plans and the amount of bonds issued.

1/ A total of 41 joint action agencies were identified but two are inactive (Kentucky-Indiana Municipal Power Association and the North Central Oklahoma Power Pool); five are in states which have not yet passed enabling legislation (Iowa-two groups, Maine, Nebraska, and Ohio); three agencies merged into one (Kansas); and one agency, Missouri Basin Municipal Power Agency (MBMPA), is incorporated in Iowa which does not have enabling legislation and is located in South Dakota. MBMPA has no financing capability but its projects are funded by other full fledged Joint Action Agencies.

2/ Enabling legislation has been passed in 28 states, but three states do not have agencies (New Hampshire, Oregon, Virginia) and two states (Indiana, Oklahoma) have inactive organizations.

TABLE 5-3: JOINT ACTION AGENCIES

Agency	Members	Estimated Demand 1979 MW	Estimated Demand 1985 MW	Estimated Demand 1990 MW	Joint Action Concept/Legislation: Concept Intro	Legis Intro	Legis Passed	Agency Formed	Plants Jointly Owned: Name	Fuel	Capacity MW	Share MW	Share %	On-line	Plants Solely Owned: Name	Fuel	Capacity MW	On-line	Wholesale Power Purchase	Financing
Northern California Power Agency	12	750-780	1000[2]		–	–	1949 1979[1]	1968	Montezuma[3]	Coal	–	160	10	late 80's	Geothermal 1 " 2 Geothermal[4] Hydro[4]		55 55 66 200	1982 1982 – 1984	Plans to be wholesale supplier to cities	–
Arkansas River Power Authority	6	4.2% annual growth			1971	1971	1973	1974[5] 1979[5]	Southeast 1[3] Southeast 2[3] Nixon 2[3]	Coal Coal Coal	500 500 500		6-12	late 80's late 80's late 80's	–		–	–	–	–
Platte River Power Authority	4	195	10% annual growth		early 1960's	1971	1973	1973[6] 1975	Yampa 1 Yampa 2	Coal Coal	400 400	140	18	late 80's	Rawhide Energy Project	Coal	250	1984	• Administers WAPA Contract • Negotiating for Federal peaking power	$237 mil
Connecticut Municipal Electric Energy Cooperative	3	120	3% annual growth		early 1970's	–	1975	1976	Millstone 3[3] Seabrook[7] Enfield-Windsor[7] Burlington[7] Vermont	UR UR Hydro Wood	1150 50 50		2	mid-80's	–	–	–	–	Negotiating wholesale power supply contracts	–
Delaware Municipal Electric Corp.	7	300	–	–	–	–	1978	1979	Feasibility study in process to study jointly owned units						–	–	–	–	–	–
Florida Municipal Power Agency	25	1083 (1978)	1646	2225	1968	–	1974[8] 1975 1979	1978	Deerhaven 2[3] Vogtle 1, 2[3] St. Lucie 2[7] Orlando 1[7] Orlando 2[7] Florida Pwr. Corp. 1[7] Florida Pwr. Corp. 2[7]	Coal UR UR Coal Coal Coal Coal	235 400 400 800 800	23.5 230 50 50 10 10	10 10	mid-81's late 80's	–	–	–	–	–	–
Municipal Electric Authority of Georgia	47	970	1219	1586	1960's	–	1975	1975	Wansley 1 " 2 Scherer 1[9] " 2 " 3 " 4 Vogtle 1 " 2 Hatch 1 " 2	Coal Coal Coal Coal Coal Coal UR UR UR UR	865 865 810 810 810 810 1150 1150 815 815		15.1 15.1 15.1 15.1 15.1 15.1 17.7 17.7 17.1 17.1	On-line On-line early 80's mid-80's late 80's late 80's mid-80's late 80's On-line On-line	Low head hydro	–	10 10	–	Purchases WS power	$850 mil
Kentucky-Indiana Municipal Power Association	(May be taken over by Indiana Municipal Power Agency. Problems with legislation in that may not be able to finance.)																			
North Iowa Municipal Electric Cooperative	14	–	–	–	1960's	Legislation still has not passed			Allied 1[7] Neal 4[7]	Coal Coal	– –	75 –		–	–	–	–	–	May serve as wholesale supplier	–
South Iowa Municipal Electric Cooperative	16	–	–	–	1960's	Legislation still has not passed			Guthrie[7] County (not an actual share but participation power)	Coal	650	50		1985	–	–	–	–	Purchase from CIPO (35MW)	–
Kansas Municipal Energy[10] Agency	32	300	3% annual growth		–	1971	1977	1978	Holcum 1[3] Wolf Creek[3] Iatan 1[3]	Coal UR Coal	280 	 63	30 5.5 –	1983 mid-80's On-line	–	–	–	–	Participation sales in Jeffrey Energy Center[11]	–

See footnotes at end of table.

TABLE 5-3: JOINT ACTION AGENCIES (CONT.)

Agency	Members	Estimated Demand MW 1979	1985	1990	Joint Action Concept/Legislation: Concept Intro	Legis Intro	Legis Passed	Agency Formed	Plants Jointly Owned: Name	Fuel	Capacity MW	Share MW	Share %	On-Line	Plants Solely Owned: Name	Fuel	Capacity MW	On-line	Wholesale Power Purchase	Financing
Northeastern Minnesota Municipal Power Agency	13	–	–	–	–	1974	1976	1977 1979	Clay Basil 4[3] Cayote[3]	Coal Coal	2000 410	– –	– –	5/80 –	–	–	–	–	–	–
Northern Municipal Power Agency	9	54	86	118	–	–	1976	1976	Cayote[3]	Coal	410	123	30	1981	–	–	–	–	–	–
Southern Minnesota Power Agency	16	300 350	–	600 (1988)	–	–	1976	1977	–	–	–	–	–	–	–	Coal[15]	300	1989	–	–
United Minnesota Municipal Power Agency	8	75	–	100	–	–	1976	1977	(Involved in long range planning project with United Power Association.)						–	–	–	–	Negotiating for participation power	–
Western Minnesota Municipal Power Agency	17	–	–	–	–	–	1976	1977	Laramie River 1 " 2 " 3	Coal Coal Coal	500 500 500	37.5 37.5 37.5	7.5 7.5 7.5	7/80 – –	–	–	–	–	–	$165 mil.
Municipal Energy Agency of Mississippi	8	–	–	–	–	1978	1978	1978	Grand Gulf[11]	UR	–	–	–	–		Hydro feasibility[15]				
Missouri Joint Municipal Electric Utility	11	–	–	–	1970	–	1977[12] 1978	1979	(Feasibility Study in process.)						–	–	–	–	–	–
Nebraska Municipal Power Pool	43	400	–	700	1973	–	1974[13]	1975	Comstock[3] Nebraska City II[3] Allied[3]	Coal Coal Coal			25	late 80's	–	–	–	–	Investigating power from Canada	–
Louisiana Energy Power Authority	6	450	2-4% growth		early 70's	1978	1979	1979/80	Big Cajun 2 1[3] " 2[3] Rodemacher 2[3]	Coal Coal Coal	560 560 560	 160	10 10 	5/80 10/80 1982	– –	– –	– –	– –	– –	– –
Dirigo Electric Cooperative		(not an agency)			(legislation not yet passed in Maine)															
Massachusetts Municipal Wholesale Electric Company	30	–	–	–	late 1960's	1971	1975	1976[14]	Pilgrim 2 Millstone 3 Seabrook 1 Seabrook 2 Montague 1 Montague 2 NEP 1 NEP 2 Wyman 4 Sears Island 1	UR UR UR UR UR UR UR UR Oil Coal	1150 1150 1150 1150 1150 1150 1150 1150 600 568		13.0 4.8 5.6 5.6 7.4 7.4 6.0 6.0 3.7 13.8	1985 1986 1982 1984 1986 1988 1986 1988 1978 1986	Stoney Brook Stoney Brook	Oil Oil	169 341	1982 1981	WS Supplier	$411 mil.
Michigan Public Power Agency	18	–	138?	–	1974	–	1976	1978	J.H. Campbell[3] Enrico Fermi[11] Midland[11] Bell River[11] Erickson[11]	Coal UR UR Coal Coal	780	37		9/80	Lowhead Hydro[15]		–	–	–	$45 mil.
Michigan South Central Power Authority	5	60.8	85.2	–	1974	–	1976	1978	–	–	–	–	–	–	Project 1 " 2 " 3	Coal Coal Coal	55 50 100	7/82 1986 1992	Interchange Agreement with Consumers Power	$94 mil.
North Carolina Municipal Power Agency 1 " 2 " 3	20 15	570	766	986[16]	–	–	1975[17] 1977	1976	Catawba 2 Catawba 1 McGuire 1 McGuire 2 Brunswick Rockboro 4 Harris Mao	UR UR UR UR UR Coal UR Coal	1145	75		1/83	–	–	–	–	Purchase 50% of base load from Duke	$700 mil.

See footnotes at end of table.

TABLE 5-3: JOINT ACTION AGENCIES (CONT.)

Agency	Members	Estimated Demand MW 1979	1985	1990	Joint Action Concept/Legislation: Concept Intro	Legis Intro	Legis Passed	Agency Formed	Plants Jointly Owned: Name	Fuel	Capacity MW	Share MW	Share %	On-line	Plants Solely Owned: Name	Fuel	Capacity MW	On-line	Wholesale Power Purchase	Financing
North Dakota Municipal Power Agency	6	–	–	–	–	–	1977[18] 1979	1979	(Supplied by Missouri Basin Power Project)						–	–	–	–	–	–
North Central Oklahoma Municipal Power Pool Authority		(inactive)													–	–	–	–	–	–
American Municipal Power Pool, Inc.	50	800-900	1000[19]	–	1968	–	–	1972[20]	Poston 5[11]	Coal	800	400		late 80's	Low head[15] hydro	–	–	–	Now purchasing wholesale needs of customers	
									" 6[11]	Coal	800	400								
Piedmont Municipal Power Agency	13	200	–	300	1974	1975	1978	1979	Catawba 2[3]	UR	–	–	25	7/85	–	–	–	–	Interchange agreement with Duke	–
Heartland Consumers Power District	17	60	105	–	–	–	1940's	1969[21] 1977	Laramie River 1	Coal	500	58	11.6	4/80	–	–	–	–	Purchase power from Omaha Power District	$240 mil.
									" 2	Coal	500	58	11.6	9/80						
									" 3	Coal	500	58	11.6	4/82						
Missouri Basin Municipal Power Agency	52	–	–	–	–	–	–	1965	(Agency unable to finance projects; relied on financing by Wyoming, Western Minnesota Joint Action Agencies and Heartland.)						(Through agreements with Joint Agencies purchases power from Missouri Basin Power Project.)				–	–
South Dakota Municipal Power Agency	–	–	–	–	–	–	1978	1978	(Participating in Missouri Basin Power Project.)						–	–	–	–	–	–
Sam Rayburn Municipal Power Agency	3	–	–	–	–	1973	1975[22] 1979	1979	Nelson 6	Coal	540	–	20	1982	–	–	–	–	–	–
Texas Municipal Power Agency	4	–	–	–	–	1973	1975	1975	Comanche[3]	UR	1150	–	62		Gibbons	Lignite	400	1982	–	$600 mil.
Intermountain Power Agency	23	–	–	–	1970	–	1977[23]	1977	IPP 1	Coal	750	–	11.2	1986	–	–	–	–	–	–
									" 2	Coal	750	–	11.2	1986						
									" 3	Coal	750	–	11.2	1986						
									" 4	Coal	750	–	11.2	1989						
Vermont Public Power Supply Authority	11	–	–	–	–	–	1976	1976	Burlington-Vermont[7]	Wood	50		30	late 83	6 hydro sites	27-30MW[15]			Investigating short term sales	–
Washington Public Power Supply System	19 PUDs 4 Municipals	9249	12059	14710[24]	–	1955(?)	1957	1957	WNP 3	UR	1100	770	70	6/86	Hanford	UR	860		–	$4.1 bil.
									" 5	UR	1100	990	90		Packwood	hydro	27			
															WNP 1	UR	1100	12/83		
															2	UR	1100	9/81		
															3	UR	1100	6/85		
Wisconsin Public Power, Inc.	38	552	717	874	1963	1975	1977	1978	Weston[3]	Coal	400	50		1983	–	–	–	–	Negotiating for wholesale power	–
									Columbia 1[3]	Coal	400	100								
									" 2[3]	Coal	400	100								
									Project 87[3]	Coal	650	50								
Wyoming Municipal Power Agency	7	20	28	–	1960	–	1975	1974[25] 1978	Laramie River 1	Coal	500	5		4/80	–	–	–	–	Supply power from WAPA	$21.5 mil.
									" 2	Coal	500	5		9/80						
									" 3	Coal	500	5		4/82						

See footnotes at end of table.

FOOTNOTES

[1] Legislation permitting establishment of a joint action entity was passed in 1949, but it was not until 1979 that legislation was passed allowing the agency to issue tax-exempt bonds.

[2] Data is noncoincident load forecast demand.

[3] Under negotiation.

[4] Plant in planning stage.

[5] ARPA was established as a nonprofit organization in 1974 and became a political subdivision of the state in 1975 with tax-exempt status.

[6] Platte River was established as a nonprofit organization in 1973 and became a political subdivision of the state in 1975 with tax-exempt status.

[7] Joint ownership possibility under feasibility study.

[8] In 1974, state constitution was amended to remove prohibition to municipals purchasing power collectively. In 1975, enabling legislation was passed, and in 1979 provision passed permitting agency to issue tax-exempt bonds.

[9] MEAG has an option for Scherer 5 and 6.

[10] Eastern Kansas Power Agency, North Central Kansas Agency and Northwest Kansas Power Agency merged into the Kansas Municipal Power Agency.

[11] In discussion stage.

[12] Enabling legislation was passed in 1977 followed by a constitutional amendment in 1978.

[13] Legislation inadequate; must go back to legislature for financing provision.

[14] Formed as nonprofit organization in 1970 and became a political subdivision of the state in 1976 with tax-exempt bonds.

[15] Under feasibility study.

[16] Noncoincident peak demand of 19 participants.

[17] A 1977 amendment permits Agencies to jointly own generating and transmission projects with private utilities and rural electric cooperatives.

[18] Legislation amended to include provisions for organizational set up.

[19] Coincident demand.

[20] Functions as a nonprofit organization until enabling legislation is passed.

[21] The District was formed in 1969 but did not become a functioning group until 1977.

[22] Enabling legislation for Texas was passed in 1975, but in 1979 amendment passed to allow the formation of the Sam Rayburn Municipal Power Agency.

[23] Legislation passed in 1965 was amended in 1977 to specifically permit municipal electric utilities to form separate legal or administrative entities.

[24] Peak demand of the 88 participants who purchased portions of the supply system.

[25] The agency was formed in 1974, but the entity was not legally binding until 1978 after the State Supreme Court upheld certain provisions of the enabling legislation.

5.3.1 Advantages of Joint Action Agencies

By grouping together and forming a distinct entity, joint action offers a number of advantages to small utilities:

- As a purchaser of an equity interest in plants, planned or under construction, the agency may have greater bargaining power by negotiating for a larger block of power which can result in a cost savings and to some degree, in more influence on the planning, construction and operation of the project. Project owners are more receptive to larger purchases because they then can avoid the administrative and accounting burden which results from a number of small purchases. Twenty-eight of the joint action agencies contacted had either negotiated or planned to negotiate for an investment share of large coal-fired or nuclear plants.

- As a purchaser of wholesale power, the agency is in a better bargaining position to obtain more reasonable prices when negotiating for a large block of power.

- The agency may have the ability to construct a large economical power plant and transmission facility. Although this is certainly a viable option for joint agencies, it does not seem to be the path taken by most of these groups. Less than half of the agencies are undertaking their own projects. Seven agencies have committed to or are constructing plants. The fuel source of the plants include one geothermal, two hydro, four coal, one oil and one nuclear. Of the seven agencies, only two have chosen to rely solely on their own generation sources for power supply. Michigan South Central Power Authority has one 55 MW coal unit with two others in the planning stage. The Washington Public Power Supply System is operating its own hydro and nuclear plants and is building five nuclear units. Small shares of two of the nuclear plants have been purchased by other utilities. Five agencies are considering building plants; four are studying hydro feasibility and the other a coal plant.

- Diversity of supply and fuel sources is possible through a joint action agency. As part of achieving the joint agency goal--to be a total or partial requirements supplier of the most economical power to their members--the agencies seek an optimum mix of resources. Three primary options exist to accomplish this: joint participation in units, constructing generation units and purchasing wholesale power. Agencies can diversify "vertically" by planning their bulk power supply in order to receive power by one, two, or all three means. Within each of these means, agencies can diversify "horizontally" by participating in, building or purchasing from the parent agencies with several units using different fuels. Most of the agencies have diversified by choosing two or more "horizontal" options. Six agencies have thus far pursued only one power supply option. However, they are investigating other options available to them.

- Joint action agencies are an attractive mechanism for raising capital. As political subdivisions of the state, the organizations can issue tax-exempt bonds. The ability to raise low-cost capital is an incentive for IOU's to encourage these groups to purchase shares of their plants. This is especially true now that IOU's are having problems obtaining capital.

5.3.2 Disadvantages of Joint Action Agencies

Joint action agencies, as with many corporate ventures, may also have disadvantages for some participants.

- o "Stronger" or "larger" utilities may gain little by joining an agency. These utilities are usually large and solvent enough to stand on their own.
- o There is continuing necessity to coordinate many independent political entities with differing needs, philosophies and resources.
- o In some cases, a municipal system may find it easier to work directly with an IOU than to participate in an agency.
- o All the agencies are relatively new and lack extensive technical expertise and operating experience.
- o Some independence must be sacrificed when a utility joins an agency.
- o Lack of access to transmission facilities can hamper a Joint Action Agency's ability to take advantage of an optimum mix of power sources.

5.3.3 Impediments to Forming a Joint Action Agency

- o Enabling legislation, the legal vehicle necessary for joint action agencies to form, requires, in most cases, a great deal of time and effort to be passed. The process requires that the legislators be educated on what joint action agencies are and what are advantages for municipal systems to participate in such an organization. In seven of the 16 states that could provide historical perspective, the idea of forming a joint action agency started in the 1960's. For the other eight states[3/] discussions on the possibility of establishing such organizations began in the early 1970's.
- o Opposition from IOU's is a problem faced by forming agencies in some areas of the country. IOU's have tried to thwart agencies by lobbying against enabling legislation. Investor-owned utility efforts were especially pronounced in the States of Kansas, Louisiana, Massachusetts, Missouri, Vermont, Wisconsin, Michigan, Florida and Georgia. In Iowa, attempts to pass legislation have been going on since the mid-1960's and are still unsuccessful.
- o IOU's can also attempt to entice cities from joining a joint action agency by offering more attractive wholesale purchase prices.
- o Lack of agreement among potential members can slow or impede the formation and functions of a joint action agency. If there is homogeneity in philosophy and needs, the members can more easily agree on planning power projects. If individual systems are in towns or cities which feel strongly about maintaining control over their own resources, turning

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3/ In the State of Washington, the concept started in the early 1950's.

over part or all of these requirements to an autonomous agency can be very threatening. In addition to coordinating the municipal systems themselves, the town councils must be convinced that joint action agencies are the best option.

- o Most of the agencies contacted noted that cooperation problems among members were experienced during their formation process, although the extent to which this impeded their development is difficult to quantify.

5.3.4 Long Term Development

The general consensus among the representatives of joint action agencies is that the problems of these organizations must be resolved at the state and local level. Federal intervention or legislation is neither needed or desired. However, a number of people did suggest that current regulations be streamlined so that in planning and constructing plants one stop is all that is needed to comply with regulations of various federal agencies.

By 1990 joint action agencies will have online 15,000 MW of capacity through joint ownership or sole construction if construction schedules and negotiations proceed as planned. This represents only about 12 percent of the capacity of small generating utilities and only 2.5 percent of all U. S. generating capacity. This capacity will supply the majority of the base load needs of 674 generating and non-generating small utilities who belong to joint action agencies.

The time it takes to pass enabling legislation and form an agency, added to the time required to negotiate for shares of or build a powerplant means that little can be done by joint agencies by 1990 if these actions are not already in place or have not begun.

Beyond 1990, joint agencies could be a dominant option for small utilities to develop and control their own resources. However, it does not appear to be an easy solution for most small utilities in complying with the Fuel Use Act prior to 1990.

5.4 TMPA - A Joint Agency Case History

The case study of Texas Municipal Power Agency (TMPA), a joint agency composed of the Cities of Bryan, Denton, Garland, and Greenville, Texas, illustrates how a group of cities, motivated by mutual financial and economic advantage, overcame political difficulties and legal problems to create and operate a joint power agency.

The complete text of this case history is printed as Appendix D to this report. The following presents a brief summary of the case history with conclusions:

5.4.1 TMPA Overview

The Texas Municipal Power Agency (TMPA) was created on July 18, 1975, by concurrent ordinances of the Texas cities of Bryan, Denton, Garland and Greenville. The creation followed the passage of enabling legislation by the State earlier in 1975. TMPA is a separate municipal corporation, a political subdivision of the State.

TMPA was created to act on behalf of the four cities for the purpose of obtaining the economic advantages of jointly financing, constructing, and operating large electric generating units and related facilities to supply the cities' future energy needs. The cities conceived TMPA as a vehicle for their entry into the nuclear and lignite fuel markets. They were responding directly to the rising costs of natural gas and oil. Prior

to the formation of TMPA, the member cities had a substantial history of joint action and cooperation. Informally, that history began in the mid-1950's. By 1963, three of the cities had entered an Interchange Agreement and had created the Texas Municipal Power Pool (TMPP). In 1969, the City of Denton joined TMPA.

According to TMPA's representative, the Texas investor-owned utilities (IOU's) cooperated, and may have encouraged, the formation of TMPA. IOU's participating in the Comanche Peak Nuclear Project were potentially impeded by the Nuclear Regulatory Commission's antitrust review process. They needed a small utility to participate in the project. TMPA provided a mechanism whereby four Texas municipally owned utilities could afford to participate in the nuclear joint venture, eliminating any potential antitrust problem.

The IOU's were consulted regarding the detailed text of the enabling legislation before its submission to the Texas legislature. As a result, certain changes were made. These were of little or no consequence to the TMPA member cities, but may reduce the likelihood of a proliferation of Texas joint agencies in the future. What emerged was relatively strong joint agency enabling legislation providing substantial financial capabilities for the member cities to apply in securing new sources of electric power generation.

5.4.2 TMPA Projects

5.3.2.1 Gibbons Creek Unit No. 1

TMPA's first generating project, Gibbons Creek Unit No. 1, is located in Grimes County, Texas. The 400 MW lignite-fired unit was 10 percent complete on January 1, 1980, and is scheduled to deliver steam-generated electricity at commercial levels by mid-1982. The project includes an adjacent surface mine, cooling reservoir, and related facilities.

5.3.2.2 Comanche Peak Steam Electric Station

On January 2, 1979, TMPA executed a Joint Ownership Agreement to acquire a 6.2 percent undivided ownership interest in the Comanche Peak Steam Electric Station at Glen Rose, Texas, consisting of two 1150 MW nuclear-fueled pressurized water reactor steam electric units together with associated nuclear fuel, switchyard, substation, railroad spur, reservoir, and an interest in a certain associated transmission line.

TMPA acquired its interest in Comanche Peak from Dallas Power and Light. The undivided ownership interests in Comanche Peak are as follows:

DP&L	23.33 percent
TP&L	28.98
TESCO	33.33
TMPA	6.20
TEX-LA	4.35
BEPCO	3.80
	100.00 percent

In January 1980, Comanche Peak was 66.2 percent complete, with Unit 1 standing at 77.3 percent and Unit 2 standing at 41.2 percent completion. Commercial operation should be realized in 1981 for Unit 1 and in 1983 for Unit 2.

5.4.2.3 Transmission Facilities

In 1979, TMPA was successful in negotiating for the transmission of electric power through existing facilities to link the Gibbons Creek and Comanche Peak generating stations.

5.4.2.4 Future Project

TMPA's next generating project will almost certainly be a second 400 MW unit at the Gibbons Creek Station in Grimes County. The site has the benefit of a settled lawsuit in which almost all affected parties were participants. (For details, see Appendix D). The site has the benefit of an existing cooling reservoir and mining operation and an enhanced opportunity for regulatory permit approvals. It is anticipated that the TMPA Directors will submit the Gibbons Creek Unit No. 2 to the member cities for formal project approval within the coming year.

5.4.3 TMPA Implications for FUA Compliance

Fua compliance by the member cities will be substantially eased by their participation in TMPA. Actions taken for primarily economic reasons caused them to anticipate FUA regulatory requirements by decreasing their dependence on natural gas and oil. While many small utilities struggle merely to understand the FUA and search for a way to comply with its provisions, TMPA consultants have completed a Preliminary Report on TMPA's FUA Compliance Strategies, identifying at least 25 different scenarios open to TMPA members for compliance with the law. The scenarios have been analyzed to estimate their relative economic value and feasibility. TMPA members are in a position to make informed choices regarding their future and to make those choices based on an extremely favorable situation for compliance with the Act.

TMPA stated that its most favorable compliance strategy is to obtain an approved system compliance plan for combined-system operation of the four member cities' existing power plants. This would permit transfer of gas between the four cities and economic dispatch operations consistent with present gas contracts. There may be problems with this approach under current DOE regulatory interpretations. It is possible that these can be worked out within the existing regulatory framework, as discussed in greater detail in Appendix D. However, it is also possible that a statutory change may be needed to permit this type of operation.

Chapter 6

Technical Options for Complying with the Fuel Use Act

6.1 Overview

This chapter discusses the technical options for generation that are, or soon will be, available to assist small utilities in reducing their dependence on petroleum and natural gas. The discussion is limited to technologies that appear to be well suited for use on a scale of 200MW or less.

Small utilities also have the option of developing conventional generating sources on a larger scale through joint ownership, as discussed in Chapter 5. However, many small utilities either do not have access to jointly-owned projects, or for other reasons would prefer to develop independent power sources. Some utilities could prolong the useful life of their existing plants by retrofitting equipment to burn alternate fuels or to improve efficiency.

The technologies considered in this chapter are grouped as follows:

- o On-site coal combustion
  - Conventional coal boilers
  - Fluidized bed combustion
  - Low-Btu gasification
- o Combustion of coal-based synthetic fuels produced off-site
  - Medium-Btu gasification
  - Coal liquids
- o Alternate fuels other than coal
  - Wood or other solid biomass
  - Municipal solid waste/refuse derived fuels
  - Biogas
  - Small hydro
  - Wind
  - Solar thermal
- o Mixtures
  - Coal/oil (retrofit)
  - Low-Btu gas from coal/natural gas (retrofit)
  - Off-peak electricity/oil or gas (in compressed air storage facility)
- o More efficient use of oil or gas
  - Combined cycle (repowering)
  - Diesel
  - Cogeneration

Some of these technologies are limited to certain regions or to certain site-specific conditions. Others will need to be demonstrated in commercial applications before small utilities would be willing to commit themselves financially. However, during the 1980's, virtually every small generating utility could seriously consider one or more of the options listed above.

6.2 On-Site Coal Combustion

Utility boilers fired by pulverized coal range in size from as small as 400,000 lbs/hour of steam (about 40 MW_e) to as large as 800 MW_e. Several decades ago, nearly all coal-fired units were in the range 400-200 MW_e, and some units in this range are still being built (see Table 3-3). Even smaller coal boilers, usually fired with stokers, are in widespread use mostly in industrial applications. Some small utilities have powerplants that were once coal-fired but were converted to oil or gas during the 1960's.

Coal-fired boilers are available from several U. S. suppliers. Equipment for the control of particulates and sulfur oxides is also available. Construction times range from four to six years. Several additional years may be required to plan and design the facility and to obtain the required permits. The use of coal generally requires a larger site than would be required for an oil- or gas-fired plant. Space is needed for receiving, storing, and handling the coal, for rail or barge facilities to deliver the coal, and for disposing of bottom ash, fly ash, and spent reagents from flue gas desulfurization (FGD).

Costs of Coal-Fired Boilers: Table 6-1 presents estimated capital cost ranges for small utility coal-fired units. These costs summarize the data presented in Table 3-3. The wide variation in cost is due to site specific factors and capital cost basis (years of construction, start up date, etc.). It should be noted that cost for boiler units less than 100MW are 15 to 20 percent higher than for the units greater than 100MW. The number of different units that made up the cost range is shown in parentheses.

TABLE 6-1
ESTIMATED COSTS FOR SMALL UTILITY COAL-FIRED BOILERS
(SOURCE: TABLE 3-3)

CAPACITY RANGE - MW	COST RANGE - $/KW
47 - 100 (6 units)	900 - 1,600
101 - 200 (2 units)	680 - 1,260
201 - 200 (3 units)	740 - 1,400
301 - 400 (2 units)	600 - 1,350

A recent study conducted by Burns and Roe, Inc., of powerplant costs in in the United States verifies the above-cost ranges. Plant costs in the 501-650MW range averaged $750+/KW for plants starting in the 1980's; plant costs for units in the 100-300MW range were approximately 30 percent greater (975+/KW). These capital costs included interest during construction and FGD scrubbers.

It is evident from Table 6-1 that small coal-fired units require a much larger investment than small oil- or gas-fired units, which typically cost about $250 per KW. Whether such an investment would be economically justified would depend on the fuel price differential between oil or gas and coal:

- The capital cost differential for the smallest units in Table 6-1 is $650 to $1,350 per KW. Assuming a 70 percent capacity factor and a 18 percent capital carrying charge, this corresponds to a capital cost differential of roughly 2¢ to 4¢/kwh.

- Assuming a typical heat rate of 10,000 Btu/kwh, the fuel cost differential would have to be at least $2 to $4 per MMBtu to offset this capital cost differential, and might have to be perhaps 50¢/MMBtu larger to also offset the higher operating and maintenance cost of a coal plant.

Although the future price differentials between coal and oil or between coal and gas are difficult to predict, it appears possible that they will be large enough to offset the extra capital cost of a small coal unit. However, many small utilities are likely to view the potential savings associated with a small coal unit as too small to justify the large front-end capital requirement and the risk of delays and cost overruns.

6.2.2 Fluidized Bed Combustion (FBC)

FBC was invented in the early 1920's in Germany and has been widely applied in several industries in various processes. Only in the past decade has it been seriously pursued as a means of steam generation for utility applications. Its major advantage is sulfur and nitrogen oxides control within the fluidized bed, which reduces or eliminates the need for post-combustion controls (such as flue gas desulfurization) for these pollutants. However, the requirement for particulate control would remain and may be intensified.

In FBC units, solid fuel particles are combusted by air in the presence of limestone particles forming a well-mixed floating mass, the "fluidized bed." Limestone contains calcium carbonate which, when heated sufficiently, releases carbon dioxide to become calcium oxide, more commonly known as "lime." The lime reacts chemically with sulfur dioxide, liberated in the combustion of coal, and becomes calcium sulfate.

Combustion of the coal in the FBC boiler is a low temperature reaction (1,500 to 1,600oF); hence the production of nitrogen oxide is minimized and slagging of the coal ash is avoided.

Coal is regarded as the primary FBC fuel for the utility industry, but FBC boilers can also burn other fuels such as municipal solid wastes, coal fines and coal cleaning wastes, agricultural waste and peat. Other possible fuels are sewage sludge, oil refinery residuals, and various industrial wastes.

Development Status: A 100,000 lbs/hour steam heating plant in Washington, D. C., is presently on-line demonstrating the feasibility of the FBC process. The Tennessee Valley Authority is due to put a 200,000 lbs/hour steam (electrical generating equivalence of 20MW) unit into pilot plant operation by 1982 with a 200MW scaled-up demonstration unit due on-line in mid-1986. Fuels other than coal are in various stages of testing in FBC units.

Constraints on the Technology: The major constraint on this technology at the present time for utility application is that it has not been demonstrated commercially. FBC systems are expected to cost between $500 to $1,000 per KW. Although the operating technology required for an FBC unit would initially be unfamiliar, the ability of FBC systems to meet SO_2 emission standards without complex and costly FGD equipment could make them more attractive economically than conventional coal-fired boilers, especially when used on a small scale.

6.2.3 Low-Btu Coal Gasification

The production of low-Btu gas from coal has been practiced for many years both in the U. S. and in other countries where coal is an abundant resource. At one time, a large number of coal gasifiers were in service in the U. S. Most of these were retired when low cost natural gas became available. Now, with gas and petroleum prices escalating, there is an increasing interest in all energy-consuming sectors in evaluating the potential for gasification.

Coal gasification systems consist of three basic operations: coal pretreatment, coal gasification, and gas purification. The pretreatment operation supplies a coal feedstock which satisfies the physical specifications of the gasification operation, and includes coal handling and storage. The coal gasification operation produces a raw low-Btu gas by reacting coal with a steam/air mixture. The raw low-Btu gas contains 40 to 50 percent nitrogen and has an energy content of 130 to 180 Btu per standard cubic foot. The gas purification operation removes undesirable constituents such as particulates, tars, oil, and acid gases from the raw gas, using cyclones, electrostatic precipitators, and water/oil scrubbers.

Generally, any coal can be gasified if proper pretreatment and gas cleaning processes are used, but certain gasifiers are better suited to some coals than others. Low-Btu gasification processes typically operate only slightly above atomospheric pressure and therefore pumping may be required or the combustion source must be located adjacent to the gasifier. Pumping of low-Btu gas for more than a few miles is not generally economical.

Use of low-Btu in existing gas-fired boilers would require burner and gas system modifications. A 15 to 30 percent derating of the boiler could result. However, if the low-Btu gas is mixed with natural gas to bring the energy content up to 300-400 Btu per scf (medium-Btu gas), no derating occurs.

Development Status: Low-Btu gasification processes have been in commercial use in the U. S. for more than 50 years. Presently, there are several low-Btu gasification plants in operation in the U. S. utilizing a number of different gasification processes. In addition, there are a number of low-Btu gasification processes under development in this country and in Europe which may have advantages over the existing commercial processes. A number of equipment suppliers are available. Construction and engineering time of three to four years is usually required.

Environmental Considerations: The environmental impacts associated with coal gasification operations range from conventional pollution problems such as coal handling dust emissions to such ill-defined problems as fugitive emissions which, because of their probable noxious character, might require special control systems. Emissions and wastes from coal preparation, handling, and storage processes can be controlled with available technology.

The feeding of coal and the withdrawal of ash from the gasifier may result in the escape of coal or ash dust, as well as potentially toxic hydrocarbons.

The gas cleaning modules also appear to present control problems with ash and water contaminated with condensable hydrocarbons, many of which are toxic. The sulfur removal processes produce fugitive emissions which are similar to those generated during gasification.

By dealing with these problems in the gasification stage, the need for post-combustion emission controls (scrubbers, precipitators) is avoided.

Costs: Capital costs for low-Btu coal gasification systems are presented in Table 6-2 for a typical low sulfur western subbituminous coal and high sulfur eastern bituminous coal, using the Wellman-Galusah gasifier. The capital costs are for a turnkey installation, including coal handling, gasification, gas purification, buildings, ductwork, engineering, start-up costs, contingencies, and working capital. These estimates are believed to be accurate within 30 percent. They indicate that the current capital cost of a small powerplant based on coal gasification is roughly comparable to, or perhaps somewhat higher than, the cost of a conventional coal-fired powerplant of the same size (Table 6-1).

Applicability: Low-Btu gasification is a proven technology which offers a number of advantages to small utility systems. Low-Btu gas, whether mixed with natural gas or not, can be fired in existing gas-fired boilers. The major disadvantage if the capital investment required and the lack of widespread use in this country. In addition, a powerplant based on coal gasification involves several technologies that would be unfamiliar to the operating personnel of small utilities (gasification, waste water treatment of organics, sulfur recovery processes).

6.3 Combustion of Coal-Based Synthetic Fuels Produced Off-Site

An alternative to the direct use of coal at the site of a small powerplant is to produce a synthetic fuel in a remote site and to transport it to the powerplant. This approach has the following advantages:

- The requirement for on-site facilities to handle and store coal, ash, and sludge is eliminated.
- The synfuels may be compatible with existing boilers that cannot burn raw coal.
- The synfuels can be produced in a large scale plant that supplies many smaller users.
- The synfuels plant can be sited close to a coal source, or in a location where environmental impact is minimized.

The major disadvantages are the large capital investment, the (possibly) higher resulting fuel cost, and the lack of existing plants to produce these synfuels.

The most likely coal-derived synfuels for utility use appear to be medium-Btu gas and heavy liquids such as solvent refined coal (SRC). High grade synfuels that are interchangeable with distillate oil or natural gas are likely to be used first in higher priority applications, such as transportation or space heating.

6.3.1 Medium-Btu Coal Gasification

The production of medium-Btu gas from coal has been practiced for many years in other countries primarily for use as a chemical feedstock. Now, there is an increasing interest in all energy-consuming sectors of the U. S. in evaluating the potential for medium-Btu gasification technology applications for both fuels and feedstocks.

TABLE 6-2
CAPITAL COST OF WELLMAN-GALUSHA LOW-BTU GASIFIERS,
WITH STRINGENT SULFUR REMOVAL

COST TYPE	GAS PRODUCTION MMBTU/HR	ELECTRIC OUTPUT MW_e (1)	COST MILLIONS	COST PER KW_e (1)
High-S Eastern	100	10	12	1,200
	200	20	18.5	925
Low-S Western	100	10	10	1,000
	200	20	16.5	825

Source: Study of Compliance Problems of Small Electric Utility Systems with the Powerplant and Industrial Fuel Use Act of 1978, Radian Corporation, Final Report, July 1980.

(1) Based on a heat rate of 10,000 Btu/KWH. Includes coal handling, gasification, and purification facilities. Does not include balance of electric powerplant.

Process Description: Coal gasification systems consist of three basic operations: coal pretreatment, coal gasification, and gas purification. In this process, oxygen and steam is used to partially combust the coal to carbon monoxide and hydrogen. Because there is still some nitrogen (although less than in low-Btu gas), the gas produced has 300 to 400 Btu's per standard cubic foot. (Natural gas, or high-Btu synthetic gas, has about 1,000 Btu per scf.)

Unlike low-Btu gas, medium-Btu gas can be economically transported by pipeline for several hundred miles. Consequently, large facilities (150 billion Btu's per day) are being planned for construction in the U. S. with the gas being piped to a variety of consumers.

Medium-Btu qas is a versatile product that can be directly fired in existing gas-fired boilers with few boiler modifications and little derating.

Cost: Medium-Btu coal gasification is more expensive than low-Btu gasification due to the cost of producing oxygen for the gasification reaction. Capital expenditures of billions of dollars are required for plants in the 150 to 300 billion Btu per day range ($1,500 to $2,000 per KW based on 10,000 Btu/kwh of electricity). Large size plants are employed to optimize the economies of scale.

Development Status: Medium-Btu gasification is a proven technology in a number of countries. South Africa has operated a Lurgi gasification facility since the mid-1950's and has just started up the largest gasification facility in the world. Plans are underway for the construction of several medium-Btu gasification plants in the U. S. Several companies presently license medium-Btu coal gasification technology in the U. S. and construction times are estimated to be four to six years.

Constraints on the Technology: The major constraints on the use of this technology in the U. S. are the large capital investments required and the fact that no plants are presently in operation in the U. S. No single small utility system could finance a medium-Btu gasification plant. However, if medium-Btu gas were available, its use would allow a utility to use existing gas-fired boilers with little modification to comply with the FUA.

6.3.2 Coal Liquids

Small utilities with existing oil-fired boilers, or with oil-capable gas-fired boilers, could be future users of liquid boiler fuels derived from coal. These synfuels could also be attractive for new plants in situations where site limitations or environmental restrictions make it difficult to use raw coal.

Processes: Liquid fuels can be produced from coal either directly, as in the solvent refined coal (SRC), H-coal, or Exxon donor-solvent processes, or indirectly via a gasification step, as in the Fischer-Tropsch and methanol processes.

Status and Cost: Indirect processes are in commercial use in South Africa and have operated in large pilot plants in the U. S. They generally produce transportation grade liquids (such as methanol or gasoline) rather than fuels that would normally be used in utility boilers. The cost of these products is currently well above world petroleum prices.

The direct processes each produce several output streams, including a substantial fraction of fuels comparable to (but cleaner than) residual fuel oil. Demonstration plants for two SRC processes will be operational by 1985, each with a daily input of about 6,000 tons of coal. If the process is technically and economically successful, large scale production could begin by 1990. The current cost estimate is roughly $40/BBL. The H-coal and Exxon donor-solvent processes have already operated on a large pilot scale and could be commercialized somewhat sooner than SRC. However, no large-scale commitment to these processes is likely until the results of the competing SRC projects are available.

Constraints: The use of coal liquids will be severely limited by lack of production capacity, at least until the early 1990's. Small utilities would not develop or own the facilities to produce these liquids but would simply buy the fuels from a supplier, probably under a long-term contract. The coal liquids should be useable in any boiler that can burn low-sulfur residual oil.

6.4 Alternate Fuels Other than Coal

6.4.1 Wood and Other Solid Biomass

There are two general methods of firing wood in a utility water-tube boiler; by burning in suspension, or by the stoker method. These boiler types are quite similar to the ones used to fire coal. Transportation costs determine whether burning wood is economically feasible. The low energy density and high moisture content of this fuel makes haulage in excess of 50 miles uneconomical. The evaporation of this moisture in the wood, before any substantial heat value for steam generation is available, results in a

considerable efficiency penalty when compared to other fuels. An alternative is to purchase pelletized wood with little moisture content, which can reduce shipping costs. However, the cost of processing the wood to pelletized form and then keeping it dry in both transportation and on-site storage may offset any savings.

Burning wood has some advantages over burning coal, particularly in regard to air pollution control. There is practically no sulfur, and relatively little ash content in wood, and the nitrogen oxides given off during combustion can be minimized by boiler design or modifications. The major air pollutant when firing wood is particulate matter.

Some utilities have access to other types of solid biomass, such as agricultural waste. Peat, which is sometimes classified as a form of biomass, is also available in a few locations, including North Carolina. These fuels require about the same combustion and pollution control equipment as wood, although there are some differences in the fuel preparation requirements.

Costs: The cost of a proposed 50MW wood-fired unit in Burlington, Vermont, is expected to be approximately $1,600/KW. The Burlington utility also estimated the installed cost of a comparable coal-fired unit to be about $1,500/KW.

Development Status: Wood is relatively new to utility applications. However, it is currently being burned with apparent success in New England by a public utility and there are plans elsewhere in the nation to use it as a primary fuel.

Environmental Constraints: Particulate matter emissions are the primary consideration for pollution control. Mechanical collectors are not adequate by themselves. Therefore, an electrostatic precipitator (ESP), or wet scrubber, or baghouse is required to remove sufficient quantities of particulate to meet the applicable standards for solid fuels. Existing control technologies should be able to satisfy such standards.

Applicability: The economic feasibility of burning wood is dependent upon the availability of forest resources or a supply of waste from forest product industry plants within 50 miles of the power plant. The technology's applicability is therefore controlled by wood supply and demand in a particular geographical region. Small utilities in these areas would have to compete with the forest industries for supplies from this source since the industries themselves will be restricted in their consumption of natural gas and oil for the same reasons that face the small utilities. Furthermore, the forest products industry may develop new products that use the residue currently being considered as a fuel. Therefore, the long-term supply of wood fuel at a competitive price is not assured. Nevertheless, the technology for direct firing of wood is proven and a small utility located in forested areas could fire wood to generate steam and electricity.

6.4.2 Municipal Solid Waste

Technology for generating steam from municipal solid waste (MSW) has existed since 1903. However, until recently there has been practically no interest in the U. S. in using MSW as a utility steam source. The recent resurgence of interest is due to (1) the greatly increased cost of alternate means of waste disposal in certain communities, and (2) increases in the cost of competing fuels for electric generation, especially oil and gas.

Processes: There are two basic classes of MSW steam generation facilities: (1) water-wall boilers that burn raw trash with no prior processing, and (2) refuse-derived fuel (RDF) systems that preprocess the raw waste into a dryer, more compact fuel with a higher heat content and better combustion properties. At least 150 feasibility studies of MSW projects are currently underway.

For economic reasons discussed below, the water-wall systems are currently the clear choice for utility applications. At least five U. S. manufacturers are currently offering water-wall systems, most based on proven European technology. Despite some difficulties with corrosion of boiler tubes and grates and other maintenance problems, the systems are considered reliable. Post-combustion recovery of metals and other non-combustible residue is normally included.

There is only one successfully operating RDF system in the U. S. (Ames, Iowa), but many others are under consideration. They offer the advantage of lower boiler capital costs and potential for use at sites where it would not be feasible to bring raw waste.

Costs: The current capital costs of electric generation from water-wall incineration are about $35 for each ton of raw MSW converted to electricity. One ton produces 500 KWH. The fuel cost of an MSW system is negative; a "tipping" fee is charged for each ton delivered to the plant. Under favorable circumstances, tipping fees can be as high as $15 per ton, resulting in a net cost of $20 per ton, or 4¢/KWH. RDF systems have a higher total capital cost (even though the boiler is cheaper). With a $45 gross cost per ton, and a $15 tipping fee, the net cost of electricity would be 6¢/KWH. At a more typical tipping fee of $5/ton, the costs per KWH for water-wall and RDF would be 6¢ and 8¢, respectively.

Applicability: There are only a few areas in the U. S. where tipping fees are in the vicinity of $15/ton. Ordinary landfills charge less than $5/ton. However, the cost of alternative disposal options is expected to rise in most areas, due to the cost of pollution controls as landfills are brought into compliance with current and future environmental standards. MSW electric generation is not economically competitive when tipping fees are only $5/ton.

An MSW system requires a large, densely populated city, with a minimum of 100,000 inhabitants, and at least 600,000 for an economically optimal operation. A 50 MW_e unit would require the waste from a city with about one million inhabitants. Therefore, only a very limited fraction of the small utilities are likely to find MSW generation attractive, and none will be able to use it to supply more than a small fraction of their needs.

6.4.3 Gasification of Agricultural Wastes

Since the natural process of biodegradation produces methane gas from all forms of animal and vegetable waste, a logical extension of this phenomena can be applied to produce this same gas for use as a fuel. This is the basis of synthetic fuel (synfuel) production from biomass. Many raw materials can be so converted to produce a useful energy source.

Process Description: One process which have proven to be economically feasible is the anaerobic bacterial digestion of cattle manure, an abundant supply of which is available at cattle feed lots. The waste is first shreded and pulverized and is then transferred to tanks where it is slurried with hot water. Soil, sand, and coarse solids are removed and the residue is heated to about 95°F. Bacteria then break the material down into ammonia, carbon dioxide, and methane gases. A scrubbing and cleaning process removes particulate matter, carbon dioxide, and water from the off-gas. After final purification, the methane, with a heating value of about 1,000 Btu/cubic feet, is piped to the end user. High-protein cattle feed and nitrogen-rich liquid fertilizer are salable by-products of the process, and help offset the cost of the process.

Development Status: A plant of 1,600,000 cubic feet per day of methane presently supplies pipeline quality gas to a gas utility in Guymon, Oklahoma. At least three other gas utilities have shown considerable interest in such a process. Funding has been made available by DOE in the pilot/demonstration stages. The City of Lamar, Colorado, also plans to build a 1,000,000 cubic feet per day facility adjacent to their natural gas-fired electricity generating station in Lamar. This process is expected to be in production within two years after ground-breaking, possibly by 1983.

Costs: To be economically viable, such plants have to be reasonably close to large feed lots with a regular supply of cattle manure. The existing plant in Guymon, Oklahoma, produces 1,600,000 cubic feet per day plant and uses 500 tons per day of manure, for which the transportation costs were about $3 per ton in 1979. The capital cost of that plant was said to be $3,500,000. If this plant operates everyday of the year (100 percent capacity factor) and if the capital carrying cost is 18 percent, the cost of the gas produced would be about $2 per MMBtu. (If the capacity factor is only 50 percent, the cost of gas would be about $3.10 per MMBtu.) This example indicates that gasification of manure (or gasification of other animal and vegetable wastes that can be gathered and transported to the plant for a few dollars a ton) could be economically attractive for small utilities that have access to large supplies of these agricultural wastes.

6.4.4 Small Hydroelectric Plants

There are a greater number of small existing dams in the U. S. that could potentially be used for power generation. Most of these dams have either never generated power or have not generated power in the recent past. Recent increases in the cost of electric power, coupled with the development in Europe of bulb turbine technology, has led to renewed interest in these sources.

Any hydroelectric facility under 30MW is considered "small," regardless of its head or streamflow. DOE currently has a program of loans for feasibility studies and separate loans to cover licensing costs. Over 100 such loans have been approved and close to 100 more are under consideration. The Administration has also established the Rural Energy Initiative--a multiagency effort coordinated by DOE--to provide financial assistance for construction of small hydro projects.

Costs: DOE studies have shown that the costs of refurbishing existing dams and installing power generation equipment varies between $1,000 and $2,500 per KW, depending on the extent to which adequate penstocks and other power-related structures are already in place. The cost of building a new small hydro dam is much higher, and would usually be prohibitive unless a substantial fraction of the cost is allocated to other functions such as flood control or irrigation.

The attractiveness of small hydro at existing dams will depend on the alternate costs of locally available power, and also on the means of financing. The cost of power from small hydro projects is generally in the range 2¢ to 6¢/KWH.

Applicability: The number and size of small hydro facilities will be limited by the inventory of existing dams. However, many municipalities have such dams within their city limits and are enthusiastic about developing these local sources. 1/

1/ The November-December 1979 issue of Public Power contains a review of the activities of public utilities in developing small hydro resources.

6.4.5 Wind

Some small utilities are located near sites that would be attractive for wind generation. A major effort is underway to develop commercially attractive wind generators suitable for utility use. These units would probably be in the size range 500 KW to 2.5 KW, so even a small utility would need to install many such units in order to obtain a significant contribution to its energy needs.

Status: DOE has tested several machines in the range 500 KW to 2 KW, and a 2.5MW prototype commercial machine is under construction in the State of Washington. Several manufacturers could offer commercial machines, based on horizontal axis (propeller) as well as vertical axis (Darrieus) designs, within the next few years. However, the test machines have had mechanical reliability problems that must be overcome before commercial production could begin.

Availability and Costs: To be cost-effective, wind generators must be mass produced. To justify setting up a production line, a manufacturer must have firm orders for at least 100 units, and perhaps several hundred. To justify placing a firm order for a large number of units, a utility must be convinced that the units will operate reliably for a normal powerplant lifetime (20 to 30 years). If all these conditions can be met, it appears likely that wind generators can be mass-produced for under $1,000 per kilowatt or about half the cost of the first prototype units. At favorable sites, this could result in power costs of 4¢ to 6¢ per kilowatt-hour.

Although small utilities cannot yet consider wind generation to be a commercially available option, this point could be reached within a few years. Wind machines can be on-line one to two years after they are ordered, so they cannot be ruled out as a means of displacing oil and gas by 1990.

Applicability: To be economically attractive, wind generators must be located in areas with steady, strong winds. There are many such areas, including portions of the South Central states where small utilities are heavily dependent on gas. Wind generators are generally regarded as sources of energy, but not of capacity (although recent studies indicate that a kilowatt of wind generation capacity would reduce the utility's required capacity by a small fraction of a kilowatt). Therefore, utilities that need to replace their gas-fired capacity to comply with the FUA could only choose wind if back-up capacity is available. This back-up capacity could be provided by converting the old gas-fired units to oil. However, gas-dependent utilities would have a greater economic incentive to invest in wind generation if the FUA were amended to permit exemptions for one megawatt of existing gas-fired capacity for each megawatt of wind capacity installed.

6.4.6 Solar Thermal

The technology for direct solar power generation that is at the most advanced stage of development appears to be the solar-steam-electric approach, although future cost breakthroughs could ultimately make photovoltaic generation more cost-effective.

Process: The technology of producing high temperatures by concentrating the sun's rays on a small area is well known. The problems of applying this technique to utility applications are primarily ones of size and efficiency, both of which impact directly on cost. This is illustrated by the 10MW solar-thermal unit in Barstow, California, which will be completed in 1981. This installation will cover some 72 acres and consist of 1,700 to 2,000 heliostats (reflecting mirrors), a central receiver (boiler) atop a 213 foot tower, and a steam turbine-generating unit. The heliostats are mechanized and instrumented to track the sun's trajectory while

reflecting its rays and concentrating them on the receiver. Steam temperatures of 900° to 1,000°F are developed which are close to the fossil-fired boiler plant steam conditions normally encountered.

Total cost of the demonstration project is estimated to be $120 million or $12,000 per peak kilowatt. The unit will be able to operate at full rated capacity for about 10 to 12 hours on cloudless days. A thermal storage system will extend the generating period by four hours at 70 percent of rated load.

Present Status of Technology: Solar-thermal power generation is being demonstrated in relatively small units in prime sunbelt sites. The Barstow unit will feed its electrical output to existing power lines once the system has been stablized. DOE is providing over 80 percent of the funding and two West Coast utilities are providing the remaining capital.

Sandia Laboratories also is producing power (5MW) from a pilot plant near Albuquerque, New Mexico. This is a forerunner of the Barstow unit.

Constraints on the Use of the Technology: Geographical location is a major constraint for utilization of the system. The Southwestern states appear to be prime candidates for system development. Land availability and aesthetic concerns may also be regarded as constraints.

Applicability: A solar-thermal plant may be regarded as an intermediate load powerplant, since its output correlates well with the daily load cycle of many utilities. Some designs include supplemental firing (gas or oil) to cover cloudy days or to permit evening operation.

6.5 Mixtures

6.5.1 Coal/Oil Mixtures

Coal-oil mixtures (COM) is an old substitute fuel (originally used to reduce coal usage) where up to 50-50 mixtures are used in a boiler designed for oil firing. At a COM plant, pulverized coal, preheated heavy fuel oil, and an emulsification additive are fed into a blender from which a homogeneous mixture emerges. The mixture is stored in a heated tank, and is agitated or recirculated to maintain the coal in suspension. The COM is pumped to rail or truck tank cars for shipment to the various plants.

In the case of the on-site COM plant, the process is identical, but in miniature, since only that facility would use the output from the mixing plant. Combustion of the COM is similar to that of firing #6 fuel oil by itself. Relatively few problems with fouling and slagging in COM boilers have been encountered. Using COM in a boiler designed for oil firing could result in a derating ranging from 5 to 20 percent.

Development Status: COM is not a new, but rather a re-emerging technology. This technology is still in the development stage for utility boiler usage. Presently, a number of trial boiler converions to COM are being tested. COM technology should be commercially available for conversion of oil-fired boilers in the 1980's.

Environmental Considerations: Existing pollution controls for coal and oil firing should be able to meet the standards for COM combustion. The type of pollutants expected from COM facilities will be the same as the oil- and coal-fired plants. However, the quantities to be controlled will be less than for a coal-fired plant and more than for an oil-fired plant.

Cost of Retrofitting for COM Firing: Where COM is involved, the sulfur content of the mixture has to be considered and pollution limitations could be the controlling factor. The capital cost of such an installation is not considered for new installations since COM is regarded as a retrofit where 100 percent coal firing is not feasible. The derating of a gas boiler to allow COM combustion, as well as the minor amount of coal that would be substituted for gas, may render such conversions impractical for boilers designed for gas firing only.

The costs of retrofitting a 100MW plant to burn COM have been estimated to be

- o $4 to $11 per KW if the plant is coal capable.
- o $48 to $55 per KW if the plant is not coal capable but can burn residual oil.
- o $71 per KW if the plant can only burn gas.

Although these costs are small, they do not include the cost of flue gas desulfurization (which might be avoided by using low-sulfur coal) nor the costs of the COM preparation plant.

Applicability: COM is particularly attractive for use in oil-fired boilers where lengthy outages, major modifications, and capital expenditures would be required to convert to coal firing. Gas-fired boilers have little or no potential for direct coal firing due to design factors. Some boilers designed for heavy oil firing have a potential for conversion to coal, but with major derating. A viable alternative may be the firing of coal and oil mixture in proportions up to 50 percent coal. Such a conversion would effectively cut oil fuel consumption in half while incurring and acceptable derating penalty on the order of 5 to 20 percent. Outage for the modification would be much less than that for coal and with prudent selection of the coal and oil, the environmental control systems could be minimized.

6.5.2 Low-Btu Gas from Coal/Natural Gas

Many existing gas-fired powerplants could burn medium-Btu gas (300 to 400 Btu/scf) with only minor modifications and little or no derating, but could not consider low-Btu gas because of site limitations (see Section 6.2.3).

Medium-Btu gas can be produced off-site directly from coal, as described in Section 6.3.1, and piped to the powerplant. However, many utilities may find it cheaper and simpler to produce low-Btu gas off-site and mix it with natural gas to produce a suitable medium-Btu gas.

- o For example, 3.25 cubic feet of low-Btu gas (150 Btu/scf) mixed with one cubic foot of natural gas (1,000 Btu/scf) would produce a mixture with a heat content of 350 Btu/scf.
- o About one-third the energy in this mixture would come from the low-Btu gas--that is, from coal.

This mixture would have roughly the same effectiveness in reducing gas consumption as coal/oil mixtures would have in reducing oil consumption.

6.5.3 Off-peak Electricity Mixed With On-peak Oil or Gas, Using Compressed Air Storage

One of the most promising new concepts involving the use of oil or gas together with energy from other fuels is the compressed air storage system (CAES).

When air is compressed and stored, the energy used in compressing that air can be partially recovered by releasing it through a suitable turbine driving an electrical generator. The air may be stored in man-made underground caverns, porous rock strata, or aquifers. The compressed air can be used to replace the compression stage of a combustion turbine, which saves about two thirds of the fuel that an ordinary combustion turbine would use. The compression can be done during off-peak hours, using power from available coal or nuclear plants. The power would then be recovered later during peak demand hours when oil or gas would otherwise be burned.

Development status: Only one CAES system is known to be operational, a 290MW system in Huntorf, Germany. It has been in service since December, 1978. The company who supplied that system also supplies the U.S. market and has been involved in consultations with DOE and EPRI. The technology is therefore commercially available, but not in widesoread use. However, Soyland Power Cooperative, a small Illinois based utility, is presently considering building a 22MW CAES and has petitioned ERA for a Fuels Mixture Exemption. Assuming that the exemption is granted, the unit is anticipated to become operational in 1984.

Constraints on the Use of the Technology: Because of the requirement for underground storage areas, the use of this technology is highly site-specific. A number of geographical areas in the U.S. do contain suitable underground storage formations. The capital cost of a CAES system will be high, but the life-cycle cost of power is expected to be competitive with power produced by a standard gas turbine.

A CAES system would be useful only if (1) there will be a surplus of available generating capacity from coal or nuclear plants during off-peak hours, and (2) power would otherwise be generated from expensive fuels (oil or gas) during peak hours.

FUA Status: Because the CAES system does use gas or oil, a FUA exemption is required. Although a CAES is generally regarded as a peaking system, the large capital investment cannot be recovered unless the plant operates more than 1500 hours per year allowed under the FUA "peakload" exemption. Therefore, the "mixtures" exemption appears to be the most suitable choice.

6.6 More Efficient Use of Oil and Gas

There are many technologies for improving the efficiency of electric generation from oil and gas. Some of these can be regarded as conservation measures that can be retrofitted to existing steam or combustion turbine facilities. Such measures would normally not change the electrical output, but would reduce the input fuel requirement. These measures are not affected by the FUA, except to the extent that they may be required as terms or conditions for granting exemptions, and they are not the subject of this section.

This section is concerned only with efficiency improvement technologies that, if retrofit to an existing plant, would alter the plant so much that it would be classified as a "new" facility, requiring a FUA exemption. Generally, such changes cause a significant net increase in the annual oil or gas consumed by the plant, even though efficiency is also improved.

6.6.1 Retrofitting of Existing Plants to Combined Cycle ("Repowering")

There are many small utility systems which have 10 to 20 year old gas or oil-fired steam units or internal combustion turbines with high heat rates and little potential to convert to alternate fuels. The thermal efficiency of these boilers is typically 20-25 percent. A possible alternative to continued inefficient operations is to retrofit the existing system to a combined cycle operation by installing a gas turbine in series with a steam boiler (topping cycle). While this may be cost effective from the utilities' standpoint, presently this would not bring the existing unit into compliance

with the FUA. Under FUA regulations (44 F F 39284, Section 500.2), retrofitting a steam plant to combine cycle operation could make it a "new" facility, requiring a FUA exemption.

Description: A combined cycle plant can be formed by adding one or more combustion turbines to a conventional steam plant, and feeding the hot turbine exhaust into a heat recovery boiler which provides all or part of the steam formerly provided by the conventional boiler. In such a "topping cycle" retrofit, the original steam-turbine generator is preserved, and additional generating capacity is obtained from the new combustion turbines. Thus, the nameplate generating capacity of the plant can double or triple as a result of this "repowering", while the overall input heat rate is reduced by about one third. The net result is a total fuel input rate 1.3 to 2 times greater than for the original plant.

A less likely repowering application, at least for small utilities, is the addition of a heat recovery boiler and a steam turbine generator to an existing combustion turbine facility. Such a "bottoming cycle" retrofit does not change the maximum hourly fuel input rate, but simply increases the electrical output. The upgraded plant is likely to be dispatched more often, so that total annual fuel consumption would increase. This may save oil or gas by reducing the operating hours of less efficient plants. On the other hand, it reduces the economic incentive to invest in a new plant fired with alternate fuels.

Costs: When older, non-reheat steam turbine generators, which may be well depreciated, are repowered with a heat recovery, gas turbine system. the cost of added capacity can be as low as $80 to $100/KW. Plant efficiency can improve to as much as 40 percent. Fuel savings can produce a good return on investment at this extreme.

Applicability: The technology of topping cycle retrofitting is applicable wherever fossil-fired units presently exist. Although these systems do not change the type of fuel used by exisiting systems, they do increase the unit efficiency. Thus, power is produced using less fuel per kwh. These systems would, in the absence of FUA restrictions, be particularly attractive to a small utility because of their low capital cost and the reduced operating cost per kwh of power generated.

6.6.2 Diesel Engines Burning Heavy Fuel Oil

Combustion of heavy fuel oils in heavy diesel engines has been practiced in Europe for many years. A number of U.S. utilities are looking at using this technology for new power installations as well as the retrofit of existing diesel engines and gas turbines to heavy fuel oil. Diesel powerplants are not covered by the FUA.

Heavy fuel engines have been used to generate electrical power in stationary service in Europe, South America and Africa for many years with excellent results, and are now receiving serious attention by a few U.S. utilities. The first such installation of a large diesel marine cross head type engine is due in service early in 1983 in Sebring, Florida. Initially, it will consist of two engines of 10MW output each for a total of 20MW added capacity. The plant will cost $18 million, an average of $900/kw, installed. Lead time, from order to completion, is about 2½ years.

6.6.3 Cogeneration

Cogeneration of electricity and steam for industrial and residential use has been practiced in this country (primarily industrial applications) and in Europe (Industrial and district heating) for many decades. As a fraction of total generating capacity, cogeneration has declined in the U.S. from about 25% in the 1930's to about 5% today. However, there has recently been a resurgence of interest in cogeneration, although this has not been accompanied by a resurgence in orders for equipment.

Most small utilities have one or more large users of steam, process heat, or space heat within their service areas, that could be candidates for cogeneration. Although congeneration is possible with any fuel, the applications that are most economically attractive involve combustion turbines and therefore require gas or oil.

FUA Status: FUA gives DOE the discretion to grant exemptions for cogeneration. DOE's basic criterion for granting a cogeneration exemption is that it result in a net lifetime savings of gas or oil, compared to the amount that would otherwise be consumed to meet the same thermal and electric needs if the exemption were denied. The demonstration of oil or gas savings must take account of the impact on utility oil and gas consumption and must also consider the impact on the utility's schedule for constructing new capacity based on alternate fuels. DOE is currently preparing rules that would expedite the granting of cogeneration exemptions in regions where oil and gas can be displaced.

Applicability: The opportunities for cogeneration are generally limited by the need for thermal energy for use in industry or in buildings. To justify the large initial investment, there must be assurance that the thermal need will remain for many years.

A cogeneration facility may be owned by a private (non-utility) firm that sells the electricity to the local utility. Under Section 210 of the Public Utility Regulatory Policy Act (P.L. 95-617), utilities must offer to buy such power at a price that reflects the "full avoided costs"...that is, the decrement in their capital and operating costs that results from not having to generate (or buy from another source) the power produced by the cogenerator. The implementation of PURPA is expected to stimulate investment in cogeneration. Further development of cogeneration would occur if utilities offer to build, own, and operate the facilities on individual sites, selling the steam to the individual user and taking the power into the grid. However, no small utilities contacted in this study expressed an interest in this type of operation.

Chapter 7

Fuel Use Act Reforms Recommended by Small Utilities

Small utilities and other interested parties contacted in this study suggested a number of legislative and regulatory changes which would reduce the impact of the Fuel Use Act (FUA) on both small and large utilities. They also suggested more narrowly targeted changes that would alleviate FUA impacts on a specific class of small utilities. A representative sample of both types of recommendations are presented in this section (in italics), followed by an evaluation by DOE of the feasibility, effectiveness, and/or equity of the suggested changes.

In some cases, DOE has already implemented the suggested change or has taken other administrative actions that make it unnecessary. Certain other suggested changes would require modification of the FUA. A number of additional suggestions are contained in the letters from small utilities, reproduced in Appendix H. Others can be found in the Case Studies (Appendix A) and in the public transcripts of meetings related to the System Compliance Option.

Legislative options are discussed in Chapter 8.

7.1 General Legislative Changes

Most of the small utility comments were general statements of concern which were not closely associated with specific changes in the wording of particular statutory or regulatory provisions. The small utilities offered their views as to where the FUA most severely impacted their operations. Their comments left no doubt that they believe small utilities to be disproportionately burdened by the FUA.

- *Many utilities simply called for repeal of the FUA on the grounds that (1) most of the desired effect of the FUA in switching utilities from gas to coal is being accomplished by market forces which began influencing utility decisions prior to passage of the FUA, and (2) the costs of securing utility compliance with the FUA to obtain the remaining, marginal benefits--costs in both public and private sectors--are prohibitive.*

Despite some calls for repeal, no utilities expressed disagreement with the basic objectives of the FUA. All agreed that oil and gas are not economically viable fuels over the long term for base load power generation, especially in new plants. DOE believes that all the FUA compliance problems identified in this study can be dealt with by far more limited measures than repeal of the Act. DOE recognizes that utility decisions are influenced by market forces which would tend to favor decreased dependence on oil and gas. However, many utilities cited the present low cost and high availability of natural gas and expressed a belief that this situation would continue. This could be taken as evidence that market forces will not assure that the finite supply of natural gas will be preserved for residential and other high priority uses. This was a primary reason for the passage of the FUA. Utilities operate in a regulatory climate that tends to discourage large capital investments, even when economically advantageous in the long run, in favor of options with low front-end costs, such as oil- or gas-fired units. DOE believes the FUA is necessary and helpful to utilities in countering this tendency. Very few utilities have expressed an intention to apply for exemptions (other than temporary exemptions, permanent peak load, or small unit exemptions, which are easy to obtain). Therefore, apart from specific problems which can be alleviated by specific measures such as those discussed below, the FUA appears to place little, if any, unreasonable regulatory burden on the majority of utilities.

- *Some utilities recommended repeal of Title III of the FUA (which applies to existing powerplants).*

Repeal of Title III would eliminate DOE's program for prohibiting, by order, existing coal-capable powerplants from using oil or gas (Section 301(b)), yet no utilities offered any specific criticism of these "coal conversion" provisions. In fact, only seven small utilities appear likely to be affected by Section 301(b). DOE believes that the conversion to coal of selected existing powerplants is in the public interest both from the viewpoint of national security and from the viewpoint of the long-run cost of electricity to consumers.

- *Virtually all small utilities that burn natural gas favor the repeal of the "off-gas provisions" (Section 301(a)). They claim that the only effect of Section 301(a) is to force them to burn oil, even when gas is available at a lower price. They believe that this would be contrary to the national objective of reducing oil imports, and would also place a severe economic burden on their consumers. Some small municipal utilities claimed that, due to their low gas consumption in 1974-76, complying with the Section 301(a) restrictions on gas use in the 1980's could make them economically unable to compete with adjacent large utilities. Other small utilities claimed that the high cost of using oil would divert revenues that could otherwise be used to develop new capacity based on alternate fuels.*

DOE recognizes that these arguments have considerable validity. However, there are at least two arguments against repeal of Section 301(a):

- Allowing utilities continued use of gas, at a cost that may be well below the cost of oil, could reduce the economic incentive to invest in new facilities, or in conversions of existing facilities to burn alternate fuels.

- In the long term, utilities would be competing for possibly scarce gas supplies against industrial buyers who have less ability to switch alternate fuels.

These arguments should be considered in deciding whether to repeal or weaken the provisions of Section 301(a). As for the specific problems of small utilities in complying with Section 301(a), DOE believes they can be remedied without repeal of this section.

7.2 Specific Legislative Changes

Some small utilities recommended changes in the FUA designed to eliminate specific problems that they face.

- *A number of small utilities called for a more equitable method of determining baseline consumption. Due to differences in the terms of gas contracts, some small utilities were heavily curtailed in the baseline years prescribed by the statute (1974-76) while other utilities, especially large ones, experienced little or no curtailment and thus have a far greater amount available in the 1980's relative to their total capacity.*

- *Some utilities in Florida and Mississippi allege that their supplies were illegally curtailed during 1974-76. They filed suit against their gas supplier and claim that they received substantial compensation for the extra oil costs for 1974-76 in an out-of-court settlement. After 1976, their gas consumption returned to its normal level, but under the FUA Section 301(a) they are limited to the very small amounts of gas they consumed in the base years. If they are forced to use oil, the utilities claim that they would face throughout the 1980's extra costs comparable to or larger than the 1974-76 costs that they recovered through litigation.*

DOE agrees that the FUA method of determining the baseline gas use unfairly discriminates against small utilities that experience unusually severe curtailments during 1974-76. The statute does not, in general, provide the flexibility for DOE to adjust the baselines.

DOE does not believe this result was intended when the FUA was enacted. Therefore, DOE supports the small utilities' request for a modification of the statutory definition of baseline gas use that would permit a more equitable treatment of all gas-dependent utilities (see Chapter 8).

- *Several small gas-dependent utilities have requested that the deadline for filing for the System Compliance Option (under Title V of the FUA) be extended beyond the statutory date of January 1, 1980. At least two utilities (Lubbock, Brazos) have stated that they probably would have filed if they had understood all the implications in late 1979, and conversations with many other small utilities indicate that they would be likely to consider filing, if offered a second chance.*

DOE recognizes that, due to staff limitations, many small utilities were not in a position to make an informed decision on system compliance before the filing deadline passed. DOE also believes that (as opposed to the unit-by-unit approach) the System Compliance Option may often be in the mutual interests of the public and the utility, and that nothing is served by prematurely closing out this option (see Chapter 8).

- *One joint action agency has requested that it be allowed to file a system compliance plan under the FUA Title V, and that it be permitted to use its annual allocation of gas in whichever of its members' units it chooses, to maximize the efficiency of the overall system operation.*

DOE agrees with the joint action agency that the mode of operation they propose would result in a net savings of gas, and sees no disadvantage in letting several utilities pool all or part of their allowed amounts of gas consumption in order to improve overall efficiency. However, DOE's current interpretation of Title V is that only a utility can file a system compliance plan. However, DOE is exploring administrative provisions that would permit the interchange of gas volumes among utilities with separate system compliance plans.

- *Many of the small utilities that have considered system compliance have determined that the post-1990 limitations on gas use are too stringent to enable to meet their needs, and feel their only choice is to apply for unit-by-unit exemptions.*

DOE recognizes that small utilities that are almost totally gas dependent today may have difficulty in achieving an 80 percent reduction in gas use by 1990, as required in Title V. System compliance was intended to provide a workable alternative to individual exemptions for gas-dependent utilities, yet only 30 of the 132 small utilities that are more than 50 percent gas-dependent remain eligible. Therefore, it may be appropriate to increase the attractiveness of the system compliance through modification of the gas consumption limits specified in Title V (see Chapter 8).

- *Some of the very small utilities have complained about complexity and cost of negotiating a system compliance plan.*

Although DOE has attempted to design the system compliance negotiating process to accommodate the needs of the various types and sizes of utilities, it recongizes that any negotiating process may be burdensome for a very small utility. This

problem could possibly be alleviated by offering an optional "package plan" for utilities below a certain size limit (perhaps 500 MW). The utility could become eligible for this plan by a simple certification process. Limits could be based on the utility's gas- or oil-fired production in 1978, regardless of which fuel was actually consumed (see Chapter 8).

- *Many small utilities that were not negotiating under the System Compliance Option claimed that the nation's interest would be better served if they were given more flexibility to use gas when available to replace oil, instead of being constrained by the limitations on gas use in the 1980's imposed by Title III.*

DOE has granted temporary public interest exemptions to assist certain utilities with this problem. However, these are of limited duration and cannot be used as a basis for planning or for obtaining long-term fuel contracts. One option, requiring a statutory change, would be to allow all utilities more flexibility under the same conditions currently allowed by DOE in the temporary public interest exemptions, until 1990. These conditions include a provision that DOE will require a switch back to oil when it determines that gas is in short supply.

- *Some small utilities have suggested that the permanent exemption for small baseload powerplants (FUA Section 312(d)) be made available to somewhat larger plants.*

DOE recognizes that raising the size limit for this exemption (currently about 25 MW) could ease the administrative burden for many small utilities. However, DOE is concerned that this would make exemptions available to many facilities that might otherwise not qualify. As long as natural gas prices remain artificially low, owners of such facilities would then have less incentive to expedite their shift to alternate fuels than they would if they were prohibited from using gas. Raising the size limit in Section 312(d) therefore appears to contradict the purpose of the Act.

7.3 Regulatory or Procedural Changes

The interim FUA rules for powerplant exemptions (44 FR 28950, May 17, 1979, 44FR 43176, July 23, 1979, 44 FR 28530, May 15, 1979) were in effect when this study was conducted. Many small utilities requested various changes in these rules, or in the administrative procedures ERA was then following in implementing the rules.

- *Nearly all small utilities complained that the rules were too complex, and that simply developing and understanding of them placed an inordinate burden on their staff.*

The complexity of the rules is due, in part, to the complexity of the statute itself, and in part to ERA's requirement that the case for granting an exemption be carefully documented. The final ERA rules are shorter and simpler than the interim rules. A number of exemptions now include certification alternatives, offering greatly simplified and reduced evidentiary requirements. It is not yet possible to evaluate the extent to which this simplification has alleviated the small utilities' earlier problems in understanding the rules.

- *Several small utilities suggested that DOE prepare and publish a "compliance handbook" explaining the meaning and potential significance of the FUA regulations. An "information clearinghouse" might supplement this handbook, providing information consultation services and disseminating information as case precedents and administrative practices develop in the course of the FUA enforcement.*

While DOE recognizes the potential usefulness of this approach, several problems could arise:

- The role of advisor to utilities considering exemptions could conflict with DOE's statutory role as the authority responsible for granting or delaying exemptions.

- A simplified description of the FUA requirements in a DOE handbook could unintentionally mislead the user into an incorrect choice of compliance strategy, whereas only the actual rules could be the basis for DOE actions regarding petitions.

For these reasons, DOE recommends that any such handbooks and related information be prepared and disseminated by organizations representing the small utilities (APPA, EEI, NRECA, various law firms, architect engineering firms, etc.). DOE would not be responsible for the accuracy of these materials, although it could assist by providing information and statutory or regulatory interpretations.

- *Several small utilities suggested that the process for obtaining the permanent exemption for existing baseload powerplants smaller than about 25 MW be simplified.*

In the Final FUA rules, the requirements for this exemption were reduced to a simple certification process, involving a declaration by the owner that the powerplant is not coal-capable and that it was a baseload plant on April 20, 1977.

- *Many small utilities complained about the filing fees for exemptions required by the interim rules, and recommended that they be abolished.*

Under the Final FUA rules, there are no filing fees.

- *Many small utilities complained that the evidentiary requirements for various exemptions are excessively complex and burdensome.*

Many of the evidentiary requirements have been simplified in the final rules. For example:

- Several exemptions have been reduced to certification processes.

- The basis for the exemption for existing powerplants based on reliability of service has been reduced to a simple "reserve margin" criterion.

- The proposed "cost test" has been simplified.

Although these and many other changes will make the final rules more workable than the interim rules, DOE intends to examine the need for further simplifying changes after it has gained some experience with the final rules.

- *Many small utilities called for a reduction of the paperwork associated with the FUA compliance (exemptions, contract submissions, etc.). Some complained that ERA was requiring information that was burdensome to prepare and was not necessary for the case at hand.*

The Final FUA rules have simplified the evidentiary and reporting requirements. Furthermore, a utility that believes the rules require unnecessary or excessive information can request, via a prepetition conference or letter, that the requirements be modified or waived. Some utilities may have overestimated the amount of detail ERA required, without proposing to ERA a simpler alternative. ERA intends to simplify evidentiary requirements on a case-by-case basis whenever this can reasonably be done without violating the statutory requirements, and, in doing so, would take into account the size of the petitioning utility.

- *Many utilities called for better coordination between Federal energy and environmental policies, and said that DOE and EPA frequently seem to work at cross-purposes with small utilities "caught in the middle."*

- *One suggested remedy was to require DOE and EPA to specifically identify and consider the "impacts on small utilities," as a separate procedural step before promulgating future regulations potentially affecting them.*

There is, in fact, substantial legislative and regulatory coordination through existing mechanisms. DOE and EPA are sensitive to these problems and continue to explore means for better coordination.

- *Some utilities recommended changes in the definition of alternate fuels. One expressed disappointment that peat was not considered an alternate fuel with respect to certain DOE demonstration grants, despite its definition as an alternate fuel under the FUA. Another suggested that alternate fuels include all refinery and industrial products having an initial boiling point in excess of 800°F, as well as all waste products that could not be burned in a conventional boiler without extensive modifications.*

ERA received a great number of comments on alternate fuels in the FUA rulemaking process, and will continually be evaluating suggested changes in the regulatory definitions of "alternate" and "commercially unmarketable" fuels.

Chapter 8
Conclusions

Although some of the compliance problems of small utilities can readily be corrected by procedural or regulatory changes, this study has identified a number of concerns that may be more difficult to correct and may eventually require legislative action.

8.1 Natural Gas Baseline

The method for computing a utility's baseline natural gas consumption could be redesigned to more accurately reflect normal patterns of gas use of small utilities. The current method places many small utilities in a disadvantageous competitive position due to the very uneven application of curtailments (some of which may not have been in compliance with applicable law) during 1974-76. There are many ways to achieve this redesign. For example, DOE could be granted the flexibility to adjust baselines to reflect normal use. Alternatively, to avoid uncertainties and disputes, a nondiscretionary standard might be specified; for example, a utility might be allowed to select any three years during the 1970's as the basis for evaluating the proportion of natural gas needed to fire a specific unit.

8.2 System Compliance Option

The deadline for filing for the System Compliance Option (January 1, 1980) could be extended to allow additional utilities to file. Many small utilities apparently did not fully understand the significance of this option, and only 38 of the 132 small utilities that are more than 50 percent gas dependent submitted letters of intent before the statutory filing date. Furthermore, the 38 small utilities that did file were required to submit compliance plans by August 1, 1980, before the final rules for exemptions for existing facilities were published, and before the outcome of their exemption petitions is known. DOE believes that the system compliance option potentially has many advantages over the unit-by-unit approach, and that utilities should be encouraged to use it.

8.3 Joint Action Agencies

If the deadline for filing a system compliance plan is extended, joint action agencies and other entities representing utilities that operate in a coordinated mode could be allowed to file a single system compliance plan on behalf of their members. Each member utility might assign its baseline consumption to the agency. After negotiating its system compliance plan, the agency could then use its allotment in any plants owned by its members, or in its own plants. This approach would assure that the allotted gas quantities are used in the most efficient plants. It would also encourage the development of joint action agencies, by enabling them to offer some cost savings to their members in the years before their first alternate fuel fired plants are completed.

8.4 System Compliance Plan

If the deadline for the System Compliance Option is extended, this would offer opportunities for making this option more attractive and workable for small utilities. For example:

- Increase the limits on gas consumption in the early 1990's, and then gradually decrease this limit in the mid- and late 1990's. This would permit a smoother transition away from gas, and might help prevent a massive shift to oil in 1990.

- Allow an operation "package" system compliance plan for which utilities below a certain size (say 500MW) could obtain approval via a simple certification process. The plan would simply specify year-by-year limits as percentages of total gas-capable generating capacity that was operational when the FUA was enacted (excluding plants that were also coal capable). No examination of actual base year consumption would be needed.

8.5 Permanent Exemptions

DOE does not recommend a statutory change in the criteria for permanent exemptions, because it believes the problems small utilities have encountered in petitioning for these exemptions can be essentially resolved by procedural or regulatory changes.

8.6 Fuel Use Act Objectives

Many small utilities recommended statutory changes that would constitute abandonment of part or all of the objective of the FUA.

- Some utilities recommended that the FUA be repealed, arguing that fuel prices were already driving utilities away from oil and gas.

- Many small utilities advocated either repealing the off-gas provisions (thus treating gas and oil identically) or at least allowing existing gas-fired powerplants to continue through their normal scheduled book life as would be allowed under Section 9 of S.2470, which the Senate passed on June 24, 1980.

DOE does not believe repeal of the FUA is needed to alleviate the perceived compliance problems of small utilities, most of whom expressed their general agreement with the basic objectives of the Act.

DOE is aware of the advantages, from the viewpoint of reducing oil imports, of treating gas no more stringently than oil, especially after gas prices are deregulated. However, until gas prices are fully deregulated, utilities may, in response to artifically low prices, use more gas than if they saw the true marginal price. This could reduce the incentive of utilities and regulatory agencies to expedite the shift to alternate fuels. It could also reduce the availability of gas to nonutility users who have less ability to shift to alternate fuels. In considering proposed legislation to repeal or weaken Section 301(a) of the FUA, Congress will have to consider these factors. DOE does not, in any case, believe repeal of Section 301(a) is justified on the basis of the problems of small utilities alone, because it believes their problems can be adequately resolved by more limited measures.